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BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

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IEPR Lead Commissioner Workshop on

Increasing Demand Response Capabilities
in California

California Energy Commission
Hearing Room A
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Sacramento, California

Monday, June 17, 2013

10:00 A.M.

Reported by:
Tahsha Sanbrailo

APPEARANCES

COMMISSIONERS

Andrew McAllister, IEPR Lead Commissioner
Robert B. Weisenmiller, Chairperson
David Hochschild, Commissioner

CALIFORNIA PUBLIC UTILITIES COMMISSION

Michel Florio, Commissioner
Carla Peterman, Commissioner
Audrey Lee, Advisor to President Peevey

CALIFORNIA INDEPENDENT SYSTEM OPERATORS

Heather Sanders

STAFF

Suzanne Korosec, IEPR Lead
David Hungerford, DR R&D Lead
Mike Gravely, Deputy Division Chief, Energy R&D Division

Also Present (* Via WebEx)

Panel 1

Sila Kiliccote, Moderator, Deputy Director of the Demand Response Research Center at Lawrence Berkeley National Laboratory

Patrick Roybal, U.S. Naval Facilities Engineering Command Southwest
*Angela Beehler, Wal-Mart
*Anthony Macdonald, Target
Veronica Hicks, Department of Water Resources

Panel 2

Mona Tierney-Lloyd, EnerNoc
Ron Dizy, Enbala
Kevin R. Evans, Energy Connect/Johnson Controls
John Rossi, Comverge

APPEARANCES

Panel 3

Joe Eto, Moderator, Lawrence Berkeley National Laboratory

*MaryBeth Tighe, Federal Energy Regulatory Commission

Susan Covino, PJM Interconnection

Joel Mickey, Electricity Reliability Council of Texas

Mike Robinson, Midcontinent Independent System Operator

Panel 4

Mary Ann Piette, Moderator, Director, DRRC

Barry Haaser, OpenADR Alliance

*John Dilliott, UC San Diego

Jacqueline DeRosa, Customized Energy Solutions

Panel 5

Heather Sanders, California Independent System Operator

Audrey Lee, California Public Utilities Commission

Bruce Kaneshiro, California Public Utilities Commission

Harlan Coomes, Sacramento Municipal Utility District

Public Comment

Catherine Hackney, Southern California Edison

Pierre Bull, NRDC

Ken Abreu, Pacific Gas & Electric Company

Anthony Brunello

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P R O C E E D I N G S

JUNE 17, 2013 10:00 A.M

MS. KOROSEC: All right, good morning everyone. I'm Suzanne Korosec. I manage the Energy Commission's Integrated Energy Policy Report Unit.

Welcome to today's IEPR workshop on Increasing Demand Response Capabilities in California.

I also want to welcome our guests on the dais, Commissioner Florio from the PUC. Thank you for joining us today.

A couple of housekeeping items before we get started. Rest rooms are in the atrium, out the double doors and to your left. Please be aware that the glass exit doors near the rest rooms are for staff, only, and will trigger an alarm if you have to try to go out that way.

There's a snack room on the second floor, at the top of the atrium stairs, under the white awning, for coffee and those kinds of things.

And for lunch we've provided a list of restaurants within walking distance, that you can pick up on the table in the foyer.

If there's an emergency and we need to evacuate the building, please follow the staff out of the building to Roosevelt Park, which is kiddie corner to the building, and wait there until we’re told that it’s safe to return.

Today’s workshop is being broadcast through our WebEx conferencing system and parties do need to be aware that you are being recorded.

We’ll make the audio recording available on our website in a couple of days and we’ll make a written transcript available in about two weeks.

In addition to time for Q and A during today’s presentations we’ll also have an opportunity for more general public comments at the end of the day. And at that point we’ll take comments, first, from those of you here in the room, followed those who are participating via WebEx and then, finally, those are on the phone, only.

When you’re making comments or asking questions please come up to the center podium and use the microphone, so we make sure the people on WebEx can hear you and so we capture your comments on the record.

And it’s also helpful if you can give our court reporter your business card, either before or after you speak, so we make sure your name and affiliation are spelled correctly.

For WebEx participants, you can use the chat function to tell our coordinator that you have a question or comment. We'll either relay your question or open your line at the appropriate time.

For phone-in only participants we'll open all of the phone lines after we've taken comments from the in-person and WebEx participants. And please keep your phone line muted until you intend to speak so that we don't get a blast of feedback when we open up all the phone lines.

We're also accepting written comments on today's topics until close of business on July 1st.

And the notice for today's workshop, which is on the table with the other handouts and it's also posted on our website, explains the process for sending in written comments to the IEPR docket.

So, just some really quick context for the workshop, Public Resources Code requires the CEC, at least every two years, to conduct assessments and forecasts of all aspects of the energy industry, supply, production, transportation, delivery, distribution, demand and prices.

Back in 2007 the IEPR talked about the contribution of price response demand response to the Energy Action Plan goal of reducing peak demand by five percent. But it pointed out that as of summer 2007 we'd achieved less than half of that.

The IEPR recommended that the CEC open a rulemaking to develop load management standards, which we did in 2008 and which we'll hear a little bit more about this morning during Mr. Hungerford's presentation.

In the 2009 IEPR, DR recommendations focused on the need for advanced meters, transparent rate information, and improved customer access to real-time information about energy use.

It also recommended continued action on the load management standards and on research and development.

In the 2011 IEPR the focus shifted more to the use of demand response to help integrate intermittent renewable resources, along with energy storage and natural gas generation.

This emphasis continued in the 2012 IEPR update, which discussed the challenges of moving from a fleet that can pretty much be ramped or turned off on demand to one that includes a lot of renewable resources that cannot, and the importance of DR as a flexible resource to help integrate those renewable resources.

The 2012 IEPR also talked about the importance of DR and the CEC's analysis of future electricity infrastructure needs in California, generally, and in Southern California in particular.

And with last week's announcement that the San

Onofre Nuclear Station has been permanently shut down, demand response becomes even more of an issue as we figure out how to maintain reliable electricity supplies.

The 2012 IEPR also included a Renewable Action Plan that recommended a variety of strategies to help California meet its RPS goals, and one of which was developing a forward procurement mechanism to make sure that we have enough flexible capacity to integrate renewable resources with the mechanism design so that all resources, included DR, storage, distributed resources, and natural gas plants can compete on a level playing field.

So, for this 2013 IEPR we're looking at DR as one of our main topics. Not just because of its potential contributions to maintaining system reliability and to integrating renewable resources, but also because despite saying since 2003 that DR shares the top slot in the loading order with energy efficiency that just hasn't really materialized.

And that's why we're addressing it in this IEPR, to take a good look at the barriers, figure out what we need to do differently, and come up with some concrete strategies and action items.

CAISO has acknowledged the importance of DR and they're developing an efficiency-in-DR roadmap to incorporate these resources in their planning and market operations. They held a workshop on May 13th to get stakeholder input and release their draft roadmap for public comments last week, which we'll hear more about in our final panel this afternoon.

Today's workshop is a follow up to the CAISO workshop and all of the materials and stakeholder comments from that workshop have been incorporated into the IEPR record.

Our agenda for today, very quickly, will begin with some brief background, followed by two panels this morning, the first focusing on the customer perspective and the second on the aggregator perspective.

After lunch, our third panel will cover enabling market structures, followed by a panel on enabling technologies, and then finish up with presentations on the regulatory and utility landscape for DR.

We'll then have a 30-minute discussion based on what we've heard throughout the day and then finish up with an opportunity for public comments.

So, as you can see we have a very full agenda. So, without further ado I'll turn to the dais for opening remarks.

Commissioner McAllister.

LEAD COMMISSIONER MC ALLISTER: Thank you, Suzanne.

I've been looking forward to this day. I think this is a great topic. And I want to -- well, first, before I start -- I'm going to make a few comments here, but before I start I want to acknowledge a few folks who are with us today.

First, Commissioner Florio, from the CPUC, thanks for joining us again. I think we're doing lots of things together with the PUC, and the Commissioners over there these days, which is really very positive, and hope to do much more of that going forward. And I know, Commissioner Florio, you feel the same.

Commissioner Hungerford -- sorry, David Hochschild, thanks for coming and being with us today. I think more, really, is better and, hopefully, we can all ask insightful questions to dig into the demand response topic.

And I wanted to acknowledge, from the ISO, Heather Sanders, who's with us as well. There we go, thanks for coming.

And also, Veronica Hicks, from Department of Water Resources, so thank you for being with us today.

And I will get some other thanks you at the end here in my comments.

I'm really looking forward to this discussion and have been for a while. The time seems to be nigh for demand response and I think the pressure on all of us is increasing to make it work at a scale that it hasn't been doing in the past.

And, you know, it's a resource the importance of which we're seeking to understand and really unlock so that it can, as Suzanne said, take its rightful place at the top of the loading order. You know, what is that magic formula?

I feel like the wizard, you know, what's it going to take to get demand response out there.

But really in the California context we are likely going to create something that's uniquely Californian and it's going to take a lot of hard work to get it done.

I'm very excited that all of you are in the room today and looking forward to working with you all to help determine what the precise pathway forward is going to look like.

So, SONGS is gone. RPS is scaling up renewables. Both of those things are very big deals for different reasons, obviously.

But it's a great time to be unlocking new flexible resources and demand side, in particular, I think as Suzanne said, number one in the loading order. So, how do we make that happen?

DR holds a lot of promise. And for today I'd really like us to come away from the discussion with more concrete ideas of the possibilities so we can begin to establish a California model that respects our goals in environment, with respect to the environment and addresses our particular history and agency structures.

So, what we produce here is very likely to be unique to California but there's a lot we can learn from other regions of the U.S.

DR, in my estimation, as I've done kind of a deep dive on this over the last few months and, really, since sitting down at the Commission, it really seems to -- it appears to mean different things to different people.

In particular, there are a lot of different versions of DR and at this moment we're more concerned, probably, about fast-response DR. What can get us resources quickly?

And what is its role and can it displace traditional supply-side resources?

Can it really meet resource needs in the traditional sense?

My particular interest here is not to limit our definition of DR but, really, to carve off the most topical part of this and focus on fast DR. It seems to be the subset we need to make real given where the RPS seems to be taking us and the shrinking baseload problem that we have more broadly.

But what is its relationship to the routine DR that we have in place, to the permanent load shifting, to economic DR and rate-driven DR?

How might these overlap? And how do they overlap with traditional sort of curtail-able type DR, where it’s N minus 1 kind of demand response?

Do these various flavors of DR cannibalize each other? That’s a big question which I, certainly, would like to have more clarity on.

Which loads can reliably fit into each type of DR, into the category of each type of DR? And what concrete products do energy users actually want or will they tolerate? That’s a big question.

And, finally, what’s our path forward? Do we build on what we’ve been doing mostly? Do we create something new? Or is there a manageable path forward that’s some of both?

That’s sort of the gist of the conversation that I would like to have today and going forward; what does the path forward look like and from what points are we beginning, really?

So, you know, it would be great to agree on exactly what it is we're talking about, so keep all that in mind as we frame this discussion. And partly this is education. I'm sure there's more knowledge here that I have in my head and I think that there are a lot of very knowledgeable people in the audience today, and participating in this proceeding.

But it's also at the end of the day there have to be some decisions made. You know, what do we need exactly and where, and how quickly do we need it, and how are we going to make that happen?

So, our goal, my goal here in the IEPR this year and at the Commission is to facilitate that conversation and get to a very concrete set of next steps going forward so that we can -- so that we can get the experiences we need, true things up, and figure out how to make it happen in practice.

So, you know, there does remain the question of what role economic dispatch can play in marshaling demand response resources. We're not really focusing on that today. We're not doing rate-making.

But I want to underscore that all of these various potential products will shape our regional net load curves in the short and the long terms and, therefore, they are inherently linked, they're related.

So, it's a tough set of questions but, happily, we don't have to answer all these questions today.

But, you know, the fundamental question and I think many of our frustration is why isn't demand response contributing more to the California supply equation than it does?

You know, we look to the east and we see what appear to be great results and an interesting marketplace and, you know, why can't we do something like that here?

So, what sort of a system might we create in California to make it more feasible for customers and positively impactful for wholesale and retail electric system operators?

So, this workshop is really a first step in answering some of those questions. I'm really looking forward to it.

I wanted to get them on the record really right at the get-go. There's a lot of richness to this discussion, there's a lot of existing experience that's going to be very valuable for charting the path forward.

But there, I think, are some bottlenecks that we've really got to figure out how to sweep out of the way so that we can have a marketplace for demand response that does marshal new technology, that applies, that does really create a market for marshaling this sort of demand side resource.

It’s going to be critical. We need that flexibility for any number of reasons.

The technology landscape has completely changed in the last ten years. Certainly, even from the last six or seven years since we last had this discussion.

So, I think the potential is there and we need to sort of get it out of the way and let it happen, and structure the market so that it can happen.

And I’m really looking forward to all of your great ideas about how to make that happen.

And then, finally -- well, not quite finally. I want to acknowledge Commissioner Carla Peterman from the PUC back in your chair. I really like that.

And before passing the mic here, I wanted to just point out that staff, I think as you’ll see, has really done a stellar job of organizing today’s workshop, in particular, David Hungerford from the Research Division.

Many of you, the panelists, probably all of you have talked with him at some point.

And for his able assistance my advisor, helping me come up to speed on this when I first took the seat here at the Commission.

Also, Mike Gravely may be in the audience here, but he's also in the Research Division and very passionate about demand response and a real font of knowledge.

And, of course, for Suzanne's team for pulling the day together within the massive undertaking that is the IEPR. I really appreciate her and her team's ongoing efforts.

So, I think today's discussion will really be worth the effort and let's get started.

So, I will pass the mic to Chair Weisenmiller here and see if he has some comments.

And thank you all, again, for coming.

CHAIRPERSON WEISENMILLER: I first want to thank everyone for being here and I wanted to thank Commissioner McAllister for his leadership on this topic.

This is a key issue for us. I think part of the things that at least I took away from the last couple of IEPRs was that a lot of our demand response programs really came out of the energy crisis. And I think in the energy crisis there was a pretty clear perception that unless you had some price elasticity built in that there was basically nothing to stop the price fights.

And so, certainly, demand response was really put in place or started really pushing in that sense to say, okay, how do we start giving people some sort of real-time pricing signals, Smart Meters? How do we really expose the customers to prices so they can respond and dampen those price spikes?

And again, so those programs -- actually, there's been a whole series of issues in terms of price signals on the retail side and how to really provide those price signals going forward.

But at least in theory that's the foundation of a lot of our programs.

The last couple of IEPRs we've really looked at how this can help us deal with renewable integration or, generally, reliability.

So, my example always is last summer when we were trying to deal with the San Onofre issues down in San Diego. And Edison, and we were looking around and trying to figure out, well, how much demand response is there and how much could we use if we, say, lost a transmission line, or lose a power plant at a key time?

And the thing that I found shocking was the answer, and SDG&E was -- although they have, I think, 209 -- anyway, they have a couple hundred megawatts of demand response, but in terms of how much could respond in that sort of half-hour context, you know, basically it was zero.

Having said that I've been told afterwards well, maybe there's two megawatts.

But the bottom line is that's not how the program is designed to deal with that.

And similarly, in Edison we were in better shape. Although, frankly, one of the things that really came to the fore there was geography matters. So, having a lot of programs out in Riverside doesn't really help in Orange County.

So, basically, again there was more there.

And then, I think in the last IEPR I pushed PG&E on how much they had that could respond in half-hour and was told, oh, a couple megawatts.

So, again, not all demand response is the same or not all demand response has the same value.

And I think there's certainly value to the 16-hour, 24-hour response. And again, thinking of the types of things that can go wrong in Southern California, we could be in the third day of a heat storm, you know. And, certainly, that will be very valuable in that context.

But again, if you're looking at renewable integration and the wind just died down, or we just lost a transmission line, or we just lost a power plant, that sort of half-hour response that we can count on just hasn’t really driven our programs very much.

And where we’ve had that, you know, if anything we’ve stepped back.

And if you go back, again, to the energy crisis DWR really stepped forward to provide that sort of direct response.

And particularly, as they’ve looked at the environmental constraints and other things on their system, at this point, the relationship with them and the ISO is more like if the ISO -- when the ISO calls them if they can respond, they will. And if they can’t, they won’t.

So, on a contingency planning basis that’s not a particularly strong relationship.

So, again, I think partially today I hope, again, continues that push.

And I think all of us, we heard at the symposium the PGM numbers were sort of like, oh, my God, how do we really grow that part? You know, the more valuable part, at least on the operational sense, part of demand response.

And I guess I’ve tried to correct myself and we’ve heard that more as auto-DR. As, you know, again, we need things which don’t need a lot of human interventions but, you know, we sort of push the button and things happen. And not calls, to calls, to calls.

So, anyway, it’s time to really invigorate things in that latter area while maintaining and continuing the progress we’ve made on the more price response of demand response.

CPUC COMMISSIONER FLORIO: Yes, thank you. I’m delighted to be here today. When I was an advocate with TURN, four or five years ago, I spent a lot of time in some working groups with ISO, PUC, Energy Commission staff developing the initial demand response products for the ISO market, the proxy demand response, and the reliability demand response.

And, you know, it’s left that world and I feel like I’m kind of parachuting back in today and it seems like, you know, several years have gone by and we really haven’t made the progress that we were hoping back then.

Some of that is due to FERC and court decisions that have gotten us a little bit sideways.

But I echo Commissioner McAllister, the time is nigh for demand response.

I think the SONGS situation particularly brings that into bold relief, the increasing importance of renewable integration.

You know, we've been talking about automated demand response and quick response for a number of years and now we really have to put our shoulders to the grindstone and make it happen here in California.

I think a number of the comments that have already been made were thought provoking for me, that going back to the energy crisis we really were looking at demand response as price mitigation.

But today, you know, energy prices aren't that volatile and energy market revenues are simply not sufficient to support the demand response that we want.

But we do have new needs and developing, new products that, hopefully, demand response will be very well-suited to provide.

You know, not talking about shutting down production lines at factories, which is a type of demand response that we can use in emergencies, but is not the kind of thing you want to do on a day-to-day basis.

But looking forward to new types of demand response where, you know, lighting can automatically dim by 10 or 20 percent or, you know, thermostats can float up a few degrees.

And, you know, the kinds of things that aren't terribly disruptive to the economy of the State, but at the same time can give us that additional flexibility in the system that we need now, both for renewable integration and for contingencies in local areas.

So, everyone seems to be working on a timeline. I see ISO has a game plan that they're putting together. Our staff is doing similar work.

I think, you know, it's vital that the ISO, the PUC and the Energy Commission all be on the same page in pulling together. That's part of why I'm here today is to try to make sure we have that coordination and are working for common purposes and not cross-purposes.

I think it's an exciting time for demand response. It's really the opportunity is there, the need is there, the will is there and I think we just need to figure out how to make it happen.

And I'm looking forward to, you know, the thoughts of all of our speakers on what we, as regulators, need to do to set the table and then get out of the way and let things happen.

I'm bullish and very hopeful that this will be the first of many successful endeavors to make demand response the vibrant part of our market that we think it can be. Thank you.

COMMISSIONER HOCHSCHILD: I'm really just here to listen today. I'm sort of ignorant, but well-meaning on demand response.

I will say, though, I mean if you look at the innovation that's happening in renewables and the cost reductions that have, you know, been realized by the State it's really impressive in just the last few years.

My sense is that the same potential exists for demand response and it's, in fact, critical, as Commissioner Florio said, and Commissioner Weisenmiller, to integrate our renewables. We need this.

So, I'm looking forward to hearing what everyone has to say about that.

CPUC COMMISSIONER PETERMAN: Good morning. Commissioner McAllister, congratulations on what looks to be a great IEPR workshop series.

Good to be here again today, enjoying this important discussion.

One of my priories as a PUC Commissioner and previously as an Energy Commissioner was working to further de-carbonize the electric sector while maintaining reliability.

And as the ISO has said, some of the three key pillars for success for renewables integration include natural gas, demand response and storage.

We know a lot about one and have a lot more work to do on the other two.

At the PUC, I have the storage proceeding and we are working actively in order to establish a procurement framework for storage.

My office put out a proposal last week for a storage procurement framework, as well as for storage targets. I'm looking forward to the feedback we'll get on the proposal. And it's really meant to generate discussion.

And we'll be having an all-party on that proposal June 25th and receiving stakeholder comments in July.

As we move forward with working to make storage more cost effective, and increasing scale and use of the system, we also need to be doing the same with demand response.

And I think it's important that we coordinate our efforts in these areas because there are many things we need to work out in terms of markets for ancillary services and such, which will apply to both areas.

I also had the electric vehicle proceeding at the Public Utilities Commission and very much interested in vehicle grid integration. We're currently scoping the next OIR to the next phase of the EV proceeding and this will be a key area.

The PUC has already approved pilots with the utilities to use electric vehicles for demand response.

And I imagine we ought to be hearing about some of that today.

So, indeed, this issue is integrated to many of the things that I'm currently working on. And Commissioner Florio has eloquently explained the general important of demand response in terms of our ongoing efforts to make sure we maintain reliability and keep costs reasonable.

I'd also like to acknowledge that President Peevey's advisor, Audrey Lee is here. And Audrey Lee is currently working on demand response initiatives with the President's Office. Indeed, this is an important issue for him as well.

And Audrey, with Commissioner McAllister's support, you're welcome to come join the dais. You may have some questions on behalf of President Peevey and we'd like to have your input.

Thanks, I'm looking forward to your feedback and discussion.

COMMISSIONER MC ALLISTER: Okay, Audrey, if you'd like to come up that would be great. There's a spare mic over here or, yeah, we can share mics. Appreciate your being here on behalf of the President.

MS. KOROSEC: All right, our first speaker is David Hungerford.

MR. HUNGERFORD: All right, well, thank you for coming, Commissioners. And I think a lot of what is in my presentation you guys have pretty much covered, so I'll move through it fairly quickly.

I was going to do a brief background on demand response.

So, just to take us back 10 or 12 years, I look around the room and I see a number of people who have been walking this path with me for the past 10 or 12 years, so you guys all know this, but we'll cover it anyway.

After restructuring failed miserably in California, the Legislature stepped in and worked at creating a way to reduce demand to be able to respond to high prices in the electricity markets.

They funded peak production programs. They spent $35 million in General Fund money to put in 25,000 meters for customers with -- large customers.

They instituted time-of-use rates for large customers with interval meters and they allocated the crisis costs only to the higher tiers of residential rates.

We'd previously had a two-tier system, a baseline and an above-baseline system. And the Investor-Owned Utilities ended up putting in five tier systems to allocate the costs of the crisis into only the higher consumption and protect the lower basic consumption from price increases.

And that has had a number allocations over the past 10 or 12 years.

Also, the CEC and the CPUC have been working together on this topic for a number of years, ever since then, and they created a joint rulemaking to start looking at ways to have demand response in California.

The first step was to think about how to get advanced meters out to all customers so that pricing could be a possibility, or programs could be a possibility so that customers could be rewarded for reducing load during peak, or that time-of-use type rates could be instituted.

So, they pursued advanced metering infrastructure business cases for the Investor-Owned Utilities.

They also created a group that worked on aggressive program and tariff development for large customers, with the State-funded meters to try to institute demand response, to try to get some price-responsive demand response out there, in addition to the emergency programs that already existed.

And the Energy Action Plan, the policy group was convened. That included the Public Utilities Commission, the Energy Commission, the Governor's Office through the Power Authority, which existed at that time, and the ISO has been a strong participant in that activity.

Okay, what -- the first major policy initiative that came out of that group was the loading order for preferred resources. That new demand, as demand grew in California, we wanted to start by meeting that demand with cost-effective energy efficiency and demand response.

After that, meet it with renewable generation, including renewable distributed generation, and only then to look at increased development of affordable and reliable conventional generation.

And, of course, looking at transmission expansion to facilitate the shift in the source of generation around the system and to be able to move power where it was needed.

The Energy Action Plan was done in three sort of iterations. And the most recent in 2008, which ended up becoming part of the Integrated Energy Policy Report process had a number of goals.

And this sort slide leaves off where Suzanne's slides of what has been happening for the past four years, five years pick up.

The first goal was to work on time-varying pricing for residential customers, dynamic pricing for all customers, programs that utilize advanced metering and other demand response, and the infrastructure to get more demand response to try to create different kinds of programs.

That's the focus on pricing that the Chairman just referred to, that we've recently been shifting to a more immediate problem of renewables integration and the SONGS outage.

We're looking at trying to work with the ISO to develop a wholesale market structure that could facilitate the inclusion of more demand response and they have been working on that. And they have made some progress, quite a bit of progress, which we'll hear about this afternoon.

And the PUC started working on developing load impact and cost-effectiveness protocols for demand response so that there was a way to measure the actual impacts and find ways to compensate, fairly, customers who participated in demand response.

And the Public Utilities Commission was successful in developing a set of demand response protocols, working with us, the Energy Commission, and they are continuing to expand and enhance that activity.

And there was a direction that the Energy Commission took to work on load management standards to establish a demand response infrastructure.

For reference, the Energy Commission does have load management authority that affects the areas of demand response and is in statute.

This is from the Title 20, of the California Code of Regulations. The creation of load management standards shall be cost effective. You can read this. And it governs all the Investor-Owned Utilities and the Publicly-Owned Utilities, as well. So, the authority extends beyond the Investor-Owned Utilities.

The main element of the authority is that the Commission can look at rate structures, it can look at storage systems, and it can look at devices for control of daily and seasonal loads.

And even though this was written in the mid-70s, the ideas still apply because it does apply to the things that we can do today and the technologies that we're developing today.

So, the objectives of today's workshop, as the Commissioners have already pointed out, we are gathering information to develop policies to make -- to expand the use of demand response, especially fast demand response, probably automated because of eliminating the difficulty of the transaction costs of individuals having to actually manipulate load when called and address the challenges from losing SONGS. And we want to keep keeping the costs low and providing automation.

And so with that, I think we can move on to Panel 1. Sila.

You can sit right there on the end. And if you would just introduce yourself, I'd appreciate it.

MS. KILICCOTE: Good morning. My name is Sila Kiliccote. I am the Deputy of the Demand Response Research Center at Lawrence Berkeley National Laboratory, and I lead the Great Integration Group there, too.

Today we have a consumer panel, a customer panel which we're really excited about. We brought in Target, Wal-Mart, and the Navy, as well as Department of Water Resources.

We're to -- actually, to prepare for this we've asked each speaker to answer four questions. And I'll share those questions with you.

And the way we're going to organize this is that each speaker is going to give us about five minutes on answering those questions and some of the important issues related to those questions.

And then we're going to ask some clarifying questions -- I'm going to ask some clarifying questions.

And then we're going to open it up to the Commissioners to ask their questions.

I'd like to thank the Commission for organizing this workshop and all our participants for participating.

And the four questions that we asked them today are:

What kind of DR programs do they participate?

What do they do when they respond and why?

What can we do in California to make participation easier for them and other customers?

And what would they need to increase their participation, particularly in ancillary services markets in California?

We have two panelists here and we have two panelists on the phone. I just want to check if they're connected right now on the phone.

Angela Beehler and Anthony Macdonald, if you're on the phone can you say you're here?

MS. BEEHLER: Yes, ma'am. This is Angie, I'm here.

MS. KILICCOTE: Hi, Angie.

MS. BEEHLER: Hello.

MR. MACDONALD: Hi Sila, this is Anthony Macdonald.

MS. KILICCOTE: Thank you, Anthony.

MR. MACDONALD: You're welcome.

MS. KILICCOTE: It looks like they're all connected.

So, I'd like to start with Patrick Roybal. He is the Smart Grid and Demand Response Program Manager at Naval Facilities Engineering Command Southwest.

Patrick's been with the Department of Defense for 12 years and has programmatic, policy, and technical experience in the fields of engineering, construction, energy efficiency, renewable generation and utility distribution.

Prior to joining the Department of Defense he was with Boeing. And he holds a Bachelor of Science in Civil Engineering and a Master of Business Administration from New Mexico State University, and is a registered professional engineer.

MR. ROYBAL: Good morning. My name's Patrick Roybal.

I want to thank the Commission for inviting the Navy to provide our perspective.

Every organization has unique situations, but there's two that I want to highlight for the Navy. The first being the Navy has a critical mission to safeguard the U.S. interests, and then we also want to highlight that there are significant loads that are attributed to the Navy ships that are ported mostly in the San Diego Metro area.

So, the critical mission that I pointed out earlier, there are potentially, and depending on how you look at those two items there could be limitations or opportunities for further demand response.

The critical mission portion, we do note that there are certain things that the Navy does that may not be a good candidate for demand response.

But, however, not everything the Navy does is critical. So, there is significant opportunity there as well. The ship loads that I was discussing, as well.

In Metro San Diego we can have up to 40 ships at any one time. Depending on the class of ship, they could range from the demand -- each ship could range from about half a megawatt up to 20 megawatts. So, an aircraft carrier, for example, is in excess of 20 megawatts. So, the minute it plugs into the grid it's significant, or the minute it unplugs.

So, it's a very dynamic load for the Navy to manage.

One other item for background is the Navy is poised to shift from a -- what we currently do, we procure future -- we do future procurement of our energy. We're looking to make a move in the next two years to basically go spot market.

So, we're going to be increasingly sensitive to the market-driven price fluctuation. So, we believe demand response is going to be very critical for the way we're going to manage that.

So, the Navy does have -- and I represent Navy Region Southwest, which comprises ten installations, nine of them located in California.

And of those nine that are in California we do have a Demand Response Program that the Navy has developed.

So, the program was developed basically in response to SONGS last year. And regardless of if we participate in a tariff demand response, our goal is to be a partner with the community and ensure the grid integrity.

The program is a three-level program. Each level is more restrictive than the last. So, in each level we can go down in load shaving.

I do want to point out at this point we've only tested up to level one, which is the least restrictive. And on that we have -- this is for the Metro San Diego area, we shaved about 4 megawatts.

So, it’s not -- and I’m going to say that the Metro San Diego area for the installations represents an approximately 50-megawatt load. So, it’s a very -- there’s opportunity there, but there’s -- and I’m going to explain some of the limitations as to why we can’t do more than that.

So, currently, the Navy does participate in demand response tariffs with SDG&E, San Diego Gas & Electric, and Southern Cal Edison.

But for the most part our participation in those programs is very small, represents a very small percentage. So, critical peak pricing is one of them. Seven small accounts, representing less than one percent of the Navy load, so it’s a very small percent, so there is opportunity for growth there.

Our current actions, so what does the Navy do when we respond? Well, let me start by saying when do we respond?

So, the Navy does respond to emergencies, emergencies issues by CAISO or the local utility company. For example, one of the times that we responded, probably the largest and saw the most significant load shedding was during the fires, so it was a few years ago.

We do participate in a few demand response tariffs, as I just described.

And in the future, as we're going to move towards spot market procurement, we're going to be looking at market- and price-driven programs to help us get through that.

So, what do we do when we respond? Automated response is one of our key tenets, but that represents approximately one percent of our shore facilities' capabilities. So, the Navy Region Southwest, again, represents nine installations in California.

There's several thousand facilities that we're managing and less than one percent of that is on automation. So, we have a very limited capability to do a 30-minute response.

And the other way we do this is we do a manual response. So, even though some of our -- roughly about 3,000 facilities, we have less than one percent on automation, and we have maybe, maybe another two percent that have networked DDC, or AWINDS, area management system.

Even though those are networked, it's a significant amount of effort for us to log in to each one of these facilities separately and then that changes.

So, we literally have to send a legion of people out to these buildings and then that changes at the facility level. So, it's not a very fast process for us. So, extremely time consuming. And what we've been able to demonstrate a day-ahead process is about the fastest we can -- at this point that we can respond to.

So, fostering more participation, some things that we are looking at would be how can we foster additional participation for the Navy?

Well, the one thing that's really inhibiting us at this point from doing widespread and fast response is that we need more visibility and control of our shore facilities.

So, as I described, we have a very small portion of that in place today.

Now, we do have ongoing projects but, again, that's chipping away slowly at the giant boulder. So, we do have expansion projects.

And then after we put those in place, the Navy has not done a very good job of sustaining the systems long term, so they degrade fairly fast and we lose that capability fairly quickly.

So, those are a couple of items of areas that we have significant issues in furthering these programs.

Also, additional metering would be very helpful for us, especially if we can segregate the ship loading from the shore loading.

So, the ship loading is very dynamic. In fact, the ship movement is classified information, so it's extremely -- from my perspective, from a facilities level, I rarely even have the opportunity to even know when these ships are coming or going, so it's hard to manage.

But if we're able to segregate -- if we're able to segregate those two loads and be able to manage those two loads separately from the shore facility perspective, we can enact significant change. And there's an opportunity for some significant DR response.

Other areas to potentially -- we've been working with Sila quite often and we're working in different ways, so perhaps additional funding for Lawrence Berkeley Labs to help the Navy develop additional DR strategies, those are some areas that we've -- we've had tremendous input from Lawrence Berkeley National Labs and their input has really helped us to carve some recent pass-forward in demand response.

Perhaps incentives or rebates for automation expansion because the expansion area for our automation is one of the key contributions to how we're going to get to where we need to be.

MS. KILICCOTE: Thank you, Patrick. And I really didn’t ask him to say that.

(Laughter)

MS. KILICCOTE: Our next speaker is Angela Beehler and she’s responsible for the implementation of Wal-Mart’s Strategic Energy Regulation Vision through regulatory policy and rate proceedings, legislative discussions, and working closely with government agencies, public utility commissions, non-governmental organizations, among many others.

She’s been with Wal-Mart for 17 years. And Angie, if you can start, go ahead, please.

MS. BEEHLER: Hi. Can you hear me?

MS. KILICCOTE: Yes.

MS. BEEHLER: Okay. Thank you so much for the opportunity to let me join you by phone today. And it’s a pleasure to share with you a little bit about our experience with demand response and give you some specific ideas of what we’ve seen across the board, what works, and what we have challenges with.

So, first of all, what kind of DR programs is Wal-Mart participating in?

Well, we participate in a little bit of everything. We participate in muni’s, we participate in utility programs, and we participate in ISO programs, PJM, ISO New England, and New York ISO to date.

Why don't Wal-Mart participate in DR and what do we do when it takes place?

Well, we like to preprogram our stores and we like to have control over our piece where demand response is taking place, and what area of our building or location, and how much is being done.

And, fortunately, we have energy monitoring facilities at all of our facilities across the United States and we have about 1,700 of our own advanced meters that we have installed.

And where we do have these in place, this has given us a lot of insight into what we're doing with energy efficiency pilots, demand response, and many of these we sub-meter, and so we get a direct line in on what we would be curtailing, if it's actually working. So, we have a way to look at it and see, to make sure that we are doing what we're saying we're doing.

So, that's given us a really breath of fresh air into energy efficiency and DR.

We certainly respond to voluntary curtailment for price response. For example, Texas, you can run up to 5,000 or 9,000 real quickly, so we've been known to run down the hall when that gets high.

We also do it for load forecasting. We look and see how much that we've purchased or need to purchase, and we can do active DR to adjust and work with that.

Of course, when the grid is in jeopardy, we always want to do the right thing and help out where possible in our stores.

Also, when we have four CPs, you know, four across the year, we want to look at it and see what we can do in demand response every day, also to curtail our load, and to manage it wisely.

And so, that's a little bit what we do. I've told you about our software, our sub-metering, where it exists.

And we like to cooperate between departments when this happens. We have people that have to take time to preprogram the load. We have time, wages involved in that. And so there is a lot of, I guess, coordination when customers actively do DR.

And so, we're happy to do that and we like to manage our load.

And there are three things that I believe in California that could make participation easier for customers.

Number one, when we've intervened in several regulatory policy proceedings in California, from 2008 to 2009, to 2010, and '11. I think in '12.

And we have several proceedings just out there just holding. A decision has been made but the final implementation of those proceedings haven't taken place.

Some of them, there's DR implications in Smart Grid. And our comments were premature there, as we're moving towards Smart Grid I think it's -- DR is a big part of that.

But I would encourage you to please listen and respond to customers that are taking the time to weigh in and invest in these proceedings, and get involved. And when a decision is made, if you could quickly implement those final rules and decisions that would, I think, go a long way in making the final rule so people know what they can invest, and go forward with, and plan for the future. That would be a tremendous help.

On the rates, we need to see clear and transparent prices, and correct allocation in these prices to see results from DR, or engagement in the market.

And the proper cost allocation of rates between the energy piece, the transmission piece and the distribution piece has been a challenge in California, specifically, to date. So, I'd ask that you look at this.

There are specific DR suggestions we would like to see from a customer perspective. It is hard to curtail for -- and this isn’t specifically in California, but if you’re asked to respond ten days in a row, that is very hard to do. We can do it, but we have executives and customers that we have to make happy in there. And if we can minimize the frequency on how much customers are called, and make sure that those events are very important.

Or, say if we do it, if we have a spurt where there are a lot of hot, hot days, if we can do it every third day, or fourth day, instead of every one in a row, that will be helpful.

Preferable advance notice of 30 to 60 minutes, and what areas would be most beneficial, that would be great. Because we have stores -- I think 250 locations all over the State, and if we would know in advance what area was needing help, we could prepare for that and make sure it’s preprogrammed correctly, and allow us to really do a lot there.

We do participate in emergency DR and price space DR. I think the design of the program is critical that it’s conducive to the customer.

If you can have no penalties involved, I think customers would be a lot less nervous in going in and doing a lot.

And if I'm doing DR, the baseline should not be penalized. So, when we provide benefits to the grid or other customer pricing to mitigate, reduce or eliminate emissions, we do all this by DR and so we are, as customers, contributing to the benefit of the grid and a clean grid.

So, if you could work with customers to not make those penalties heavy or work with them on penalties, that would be appreciated.

And on ancillary services for California, we're curious about CAISO markets and why there is not bidding into of curtailment or loads into CAISO, yet.

We did a pilot with CAISO in 2008, I believe it was, and showed also that customers can respond.

As I mentioned earlier, if you can give commercial customers shorter blocks of time and give them a recoup time, also, after you curtail and really go to the mat to reduce HVAC, or spare lighting around, if you can have a ramp back to normal time, and then a couple hours later do it for another hour for less I think you would see a huge participation in that we could float back to normal and then participate again.

So, program design and penalties would be important, the notice time, and make there be no obligation to bid for every segment of every hour. And to let -- you know, if you want to bid in once every two hours for 15, 30 minutes or an hour, and then have a breather of a couple of hours that would be awesome and, really, I think, spur a lot of creativity there.

And we are currently evaluating different technologies. We've done two different pilots recently where we cooperated with PJM and IPKeys and did some direct signaling from PJM to us as a customer, and responded on price and showed that customers could actually receive the price and respond back to the ISO on OpenADR 2.0.

And we have another current pilot that we can talk more about later, that we are taking this to the next level. And when I can talk about it, I'll be happy to do that.

But customers are getting very involved in DR. And if the program rules are set right and the opportunities to participate to maximize that, we can make a big difference. And we would love to be a part and help CAISO, and California Utilities, and the State through some resource opportunities and going forward in the future.

And thanks so much for letting me visit with you today.

MS. KILICCOTE: Thank you, Angie.

Our next speaker is Anthony Macdonald, he's with Target. And, Anthony, I've opened the line for you, so if you could introduce yourself.

MR. MACDONALD: Sure. I apologize with that. I tried to get it done Friday, but I had a slight family emergency I had to take care of so I wasn't able to do that.

Thanks everyone for having me on board. As Sila said, my name is Anthony Macdonald. I work for Target Corporation. I've been here for two years. I lead our Demand Management Programs and demand response is a big part of that, along with energy analytics, sub-metering and a variety of other initiatives on the demand side.

Prior to that, I worked for a small electric cooperative and energy consulting firm for over the past eight years.

So, I'll jump right into this. Target is really committed and has made a significant investment in sustainability. You know, in many areas, but especially in the area of electricity sustainability and reduction. And we are really focused on reducing our carbon and water usage, you know, with our current goal of reducing our energy by 10 percent by the end of 2015.

In addition, we have a significant investment in LEAD. All of our chain stores, 124 this year, will be

LEAD certified at some level, also, a large variety of stores across the rest of the State -- the rest of the country. And demand response is one of the programs we actually give points for within our lead initiatives.

By the end of 2013 we'll have about 1,925 locations in the U.S. and Canada and approximately 50 percent are enrolled in some type of demand response program with a curtail-able load of somewhere between, you know, 60 and 70 megawatts that we can control.

So, one of the questions, we participate in a large variety of demand response initiatives and programs across the country. Capacity programs, in PJM in California, economic programs, direct load control, which is kind of prevalent in the Midwest where we don't have too many specific demand response programs due to load control over RTUs.

We do this through a variety of methods. So, we utilize innovators in most locations, but we also partner directly with the utility for municipals and cooperatives.

One example of that is we enrolled with SMUD this year, we have about 11 stores in SMUD and we enrolled all of those stores into their auto demand response program. I believe we're working with them for about six months on that.

We also do a variety of price response programs. We're not enrolled in some sort of market, specifically, in the southeast, Texas and Georgia is kind of our two key areas there, but we do participate in Florida and along the east coast, as well.

So, what do we do when we curtail? So, we have BMS and sub-metering at every one of our sites, that the building management system is back to headquarters, every site is, and so we have an application we built that partially automates every program for us so we can reach out to every store and touch. And we're able to do that for every site within about ten minutes, if asked to do that.

And during these events we do a couple of things. We do HVAC shutoff. We shut off about 30 percent of our HVAC units. We change temperatures on the other units, depending on the area in the store, and we also shed about 50 percent of our lights, you know, on the sales floor.

And this is pretty standard procedure across the country for all of our locations. We load that into our building management system so there's no changed to be made as we go, and we're able to see on the fly what's happening, if our sites are curtailing and what is causing it to curtail correctly or not to curtail. So, we actually have a very easy program that we can utilize to do all that.

And we participate in a variety of programs from ten minutes' response time to I think our longest is four hours. We don't do much a day ahead. We're engaged in the more quick demand response programs.

But for the ten minutes we need a program which is fully automated. We utilized, you know, the open -- you know, the OpenADR standards in some markets and some proprietary standards that we've implemented.

So for us, you know, what can we do to make participation easier? So, a lot of what we look for is consistency. So, we've seen a lot of changes through programs across the country and California a lot this last year, actually, so consistent prices and programs in the State and from year to year.

One of the examples I have is in SDG&E this year we had an aggregator back out of the market and so we had to quickly find someone else to take our stores in that market. And the feedback they gave us was there's just some changes in the SDG&E program which led it to not be favorable for them and so they backed out of that market. And that kind of put us in a bind, we only had a few weeks to lock down someone else and get all our stores enrolled. So, you know, consistency's really important for us.

And also, you know, for us we love auto demand response, you know, as we have almost a thousand stores and programs it's very hard for us to engage where we're not automated, especially if you try to continue with our programs.

And so, if we can do whatever we can to automate those programs, specifically working with aggregators. So all through California, except for SMUD, we enroll with aggregators.

And where possible, you know, partner with them to drive that auto demand response. We've done some pilots with SCE, specifically, I think two years ago where we worked with them on auto demand response through them, with response time, but it wasn't through our aggregator.

And so for me, if we can partner with aggregators to do that, that is great.

And to echo some of Angie's comments, flexibility for us in enrollment, bidding and program structure are really important. You know, so our guest experience is very important for us.

And if we have the ability to change our bids on an hourly basis, change enrollment, you know, weekly or daily -- not day by day but, you know, ahead of time we'll know, okay, we're not going to enroll on Tuesdays, we're not going to enroll before 10:00 a.m.

For us, we really have no load prior to 8:00 or 9:00 and, you know, after 8:00 or 9:00 at night, so those programs require us to go early in the day and late at night, and then it makes it very hard for us to response as needed.

So, just some flexibility in enrollment in bidding and program structure is really key for us as we move forward.

And one other thing that I ask is focus on education of the end-user or, you know, the people of the State. If we can make sure we have educated guests, they understand what we're doing and then we don't see the negative connotations of having lights off or a little warmer temperature in the store.

The one thing we want to do is make sure that environment's the best we can for our guests and that's key to really having an educated guess.

We provide some notification to our guests during the program but, you know, not everyone's going to be able to see what's going on and might wonder what's happening in our location. So, those are kind of the key for us.

But what it comes down to is we participate in basically every market we can across the country. We believe this is, you know, good for Target, good for the communities we invest in. And we feel that wherever we can do these types of programs that we will enroll in them. But they have to meet what we need and meet the different requirements that we have.

And if we can make those flexible enough for us and frankly, have a good return for us then we'll continue to do that across the country and especially in California.

You know, we have about 190 stores enrolled in programs in California. And as we have the ability to do more, we'll continue to do more, especially if we have good flexibility and good program consistency across the State.

MS. KILICCOTE: Thank you, Anthony.

MR. MACDONALD: Thank you.

MS. KILICCOTE: Our last panelist is Veronica Hicks. And I don't have a bio for you, as well, Veronica, so if you could please introduce yourself.

MS. HICKS: Sure. Good morning. It's a pleasure to be here this morning on behalf of Department of Water Resources. Hello.

My name is Veronica Hicks and I'm over the State Water Project Power and Risk Office with the Department of Water Resources. So, essentially, we do everything related to power, transmission, greenhouse gas reduction and a host of other issues.

I've been with the Department 34 years and was involved during the Department's efforts during the energy crisis and stemming from that then transitioned over to State Water Project Energy.

So, as you know, DWR, the State Water Project is -- participates in the wholesale market. So, we are our own scheduling coordinator and we work very closely with CAISO.

Energy costs is the largest component of costs for the State Water Project, representing about 40 percent of the project's cost, about $400 million a year. So, there is an incentive and there was an incentive when it was built to design the project and maximize off-peak pumping.

But in more recent years the flexibility we had to shape that has been limited from environmental restrictions. And also, the project's now 30 to 40 years old. Aging infrastructures, we've had some catastrophic failures. Operating availability is very limited.

And the reason I say this is that it's -- it is limiting the ability of the Department to be flexible to move its load around. However, we are always trying to maximize off-peak pumping.

We participate in several ways with CAISO as a wholesaler. We have a participating load agreement with CAISO. And even though -- what this does is allows CAISO to drop our load. It's essentially an ancillary services non-spin product.

And we bid this in similar to what a generator could do to increase load.

Even though CAISO's tariff does not consider participating load as demand response, it's referred to that in their annual demand response program.

So, it mimics a generator that, instead of increasing load, increasing gen we can drop the load.

So, under this participating load agreement we do put in bids, non-spin, in the day ahead and we do this both for resource adequacy and for ancillary services.

Historically, pre-MRTU, we could also put bids in to increase the load. So, in times when there's over-generation we could be called upon to automatically increase our load.

And we also could put in these ancillary services non-spin bids in the day ahead.

Well, as a result of MRTU and the market redesign those two products are no longer available and we're not able to bid into those services.

So, something we're discussing with the CAISO, we understand it involves significant software changes, et cetera.

But if we had the ability to put in bids to increase load or participate in the hour-ahead ancillary service market under the participating load agreement that could even be on a spin basis, so readily available to CAISO.

What would be needed to increase our participation? I think those two market products, as well as, you know, the Department does have a vision to get back the robust functionality of the State Water Project System. And when we get there we will be able to be much more active and put our bids in more frequently.

I should state that, you know, our mission is to deliver water and as such water really drives the power schedules.

Now, within that constraint we do try to optimize the energy component of it.

Years ago, around 2000, we also had a demand response contract with PG&E and this provided for the months of June through September we could bid in a month ahead of time how many hours, limit on how many days that we could drop load in that month. And it was fairly successful but towards the end, with the operational limitations we had and, of course, everything varies with the hydrology, we weren't able to put in any bids.

But for a few years that worked very well for us and it worked well for the utility.

And again, once we get some of our OA, operational availability back that's another product that we could look at, as well.

And so I look forward to your questions and talking more about the State Water Project. Thank you.

MS. KILICCOTE: I'd like to thank, again, all of our panelists for joining and sharing their experiences. I'd like to see if you have any questions right now.

COMMISSIONER MC ALLISTER: So, yeah, very interesting. Thanks very much. And I do -- I made copious notes here, so I will be somewhat cogent in figuring out what my questions actually were.

Let's see, I guess for the Navy, Patrick, I was wondering -- you talked about those resources degrading over time and I wanted to dig in a little bit on that and see what that meant in practice. Are those human resources, are those -- what exactly degrades over time?

You know, if you don't use them do they kind of literally get rusty, or they figuratively get rusty, I guess?

MR. ROYBAL: Right. It's multiple ways that it degrades. One is currently we don't really have the skill set with the personnel that are there. So, as these systems get more and more sophisticated we have operators and mechanics that are not keeping up with the technology as fast as they should be. And, therefore, when we should be sending somebody with a laptop to go integrate with a control, they're literally going out with a hammer. So, they're using the wrong tool.

So, we don't have our skill set in our training programs at the deck plate level, you know, at the mechanic level to do the right work on the systems that we're putting in place now.

And then we do have -- we've been doing this in our facilities for probably about 20 years or so. So, we have a range of systems that do require a hammer and a wrench, all the way to something that's very sophisticated and requiring a laptop at this point.

So, we have a wide range of these type of systems and a limited skill set of operators and mechanics. So that's one area.

The second area is because of those skill sets and also funding limitations we don't always have -- we don't always have the proper resourcing in order to maintain these systems the way they should be maintained. So, the Navy has a finite budget and they use those resources, you know, as needed and the prioritization of those resources doesn't always equate to putting the resources in those type of facilities, at those systems.

So, over time we do have degradation of those systems. It could be anything from a rusting system to a rat chewed through the fiber optic cable. So, it ranges the gamut.

But if we don't have the resources to fix those situations, over time we get systems that are not -- either are not working, period, or are working at a significantly reduced efficiency.

COMMISSIONER MC ALLISTER: Now, are you -- I assume your sort of dispatch agreement or your demand response participation is directly with the utility, right? I mean you're big enough.

MR. ROYBAL: Of the nine installations that are in California we have --

COMMISSIONER MC ALLISTER: Yes.

MR. ROYBAL: -- the majority of them are direct with a utility company. There is one that is using an aggregator, but for the most part it's directly with the utility company.

COMMISSIONER MC ALLISTER: Okay.

MR. ROYBAL: I think that was your question, correct?

COMMISSIONER MC ALLISTER: Yeah. I guess I'm just wondering -- well, really, I guess my fundamental question is what -- you know, with the fires I think, you know, the Navy would -- the fires down in Southern California, for example, installations down in that part of the world I think were instrumental in helping weather that storm, as it were.

But at the same time, you know, I think it was necessary and the Navy rolled up its sleeves and got it done. But sort of in retrospect it was like, okay, it would be good to have that -- you know, the arrangements, and the settlement, and the sort of economic value proposition fixed beforehand so that we kind of know what we're getting into rather than doing it kind of on the fly.

And I guess I'm wondering sort of since then or, you know, currently, what's the value proposition for you to be doing this? You know, presumably, there needs to be some upside for you to be able to dedicate the resources. You know, is that the case? Where are you in sort of working out those kinds of issues right now?

MR. ROYBAL: Right now, for large-scale implementation what we're finding is that we have limited funds to put these in place.

One of the things, when it goes to the DC beltway for funding is the most sure return on investment. So, for us it's been extremely difficult to quantify some of those aspects of it.

Obviously, some of our counterparts in the private sector have figured that out otherwise they wouldn't be -- they're working towards the bottom dollar. And so there's a way that they've figured this out or they've made a conscious decision to say regardless of what the impacts are this is the right thing to do, for various reasons.

Right now in the beltway, in Washington D.C., it's bottom dollar, most sure return on investment, especially during these sequestration times where we're trying to really reduce and scrutinize the expenditures.

So, that's a limitation for us in trying to further our Smart Grid capabilities and, as part of that, being able to respond quickly in demand response.

COMMISSIONER MC ALLISTER: Thanks very much.

So, is Ms. Beehler from Wal-Mart still on the line?

MS. KILICCOTE: Angie, are you still on the line?

MS. BEEHLER: Yes.

COMMISSIONER MC ALLISTER: Hey, thanks for hanging with us.

MS. BEEHLER: Sure.

COMMISSIONER MC ALLISTER: You know, I was interested in a little more detail about how you -- sort of what your dispatch and operation looks like. You must have sort of a team of people and some fairly real-time information there. And it would be nice to sort of understand that and what the impact on a given -- so, how you're monitoring at the sort of regional, or even the individual store level to make decisions on the fly as to how you're going to dispatch demand side resources and how you actually do that control.

I think you mentioned that you work with some aggregators, but I'm -- if you could put a little more flesh on those bones, that would be great.

MS. BEEHLER: Yes, we do. Well, there are several areas of the country where we are securing our own load now. And within those ISOs I think there are opportunities there.

But what we do is since we already have -- we've had energy-monitoring facilities at all of our stores across the states for many years.

But what we do is we have the opportunity to see them via software here, at our headquarters. And we look at those and where we have metering already, our own advanced meters in place, or sub-metering at part of those facilities, again, it refers back to the previous comments on ROI. Where can we install those advanced meters and where we can install sub-metering and provide the ROI to that equipment back to our stores.

But we have a whole group of, oh, about a hundred associates that stop -- that monitor all of the alarms from our energy facilities around the clock here.

And within that we coordinate our energy department, specifically coordinates directly with them via demand response opportunities in the future, and that we want to do.

And we program, we have the opportunity -- but we are currently looking at different technologies as more and more emphasis comes with energy efficiency and integrating our renewables that we have. We have a lot of rooftop solar. We have some fuel cells. We have some digester projects that feed, you know, gas into our stores.

And as we're looking at all of this feeding in together we have to have some kind of transparency there. And as we do this, we coordinate with our facilities monitoring people, our energy department does, and say we have an opportunity in an hour to participate with this utility, or this zone of an ISO, and we're going to do it on price responsive. Have we curtailed in this zone before? What do we have -- stores do we have within that zone? Do we have them preprogrammed in? What areas within the store would we like to curtail?

So then all we have to do is execute on that preprogram and either we are doing some pilots, as I said, with direct signals and we can receive those, and depending on the way or, you know, which way we do want to do demand response, but we certainly can go a lot further. If it's a short time period within the stores and a repeat period that we can do it, we can make a lot of difference there.

COMMISSIONER MC ALLISTER: I really appreciate your answer. And rather than dig in more, which I'm really tempted to do, I want to just say, you know, I really hope we can count on you to help us figure out what motivates a large customer, like Wal-Mart.

I think there's also a conversation that needs to happen, sort of what -- for smaller customers and customers that maybe are more predisposed to using an aggregator, sort of what that whole set of transactions look like.

But for, I think, important, for very large customers of multiple facilities, like you and like Target, there’s a lot to be learned because you’ve already thought through a lot of the value proposition, so I think we could take advantage of that to help design a market that actually does mobilize that kind of resource.

So, thank you very much and I really look forward to your ongoing participation in this.

MS. BEEHLER: Right. I didn’t -- we do use aggregators so --

COMMISSIONER MC ALLISTER: Oh, okay.

MS. BEEHLER: There is a lot of value that aggregators can bring to customers. For example, they might have a huge load where they can even out different participants.

And say if you had your CEO walk in the store and it’s Christmas Eve, and we can’t curtail at that time, sometimes there’s opportunities. There again, the penalties fall into play. But if you’re relying on an aggregator, with a lot of other facilities, there are opportunities and benefits of services and flexibilities aggregators can bring to the table.

COMMISSIONER MC ALLISTER: Thanks very much. I'll just point out that, you know, if an Energy Commissioner comes to one of your stores you should -- you should deploy your resource, rather than not deploying your resources.

MS. BEEHLER: That's right. I agree with that and we'd be happy to give them a tour.

COMMISSIONER MC ALLISTER: Yeah, we'll give you the heads up so you can deploy those resources when we're in the building.

MS. BEEHLER: Sure.

COMMISSIONER MC ALLISTER: Let's see, so just one quick other question here. So, in a given facility, for example, would you have some resources that you are controlling and dispatching from your headquarters based on, you know, a particular set of product characteristics that you're bringing to the market or, you know, you're working with the ISO or something to deploy, at the same time you might have other products that you're working with aggregators to deploy, to mobilize and deploy, like at the same store or the same region?

MS. BEEHLER: You know what I think I know what you're saying. For example, an ancillary service opportunity and a demand response event?

COMMISSIONER MC ALLISTER: Yes.

MS. BEEHLER: Or proactive curtailment on energy price.

COMMISSIONER MC ALLISTER: Exactly.

MS. BEEHLER: Correct.

COMMISSIONER MC ALLISTER: Uh-hum.

MS. BEEHLER: I think there are opportunities when these do overlap, but I believe they have totally different purposes.

For example, you might just have a normal DR event, but you might have a different kind of opportunity need as well, at the same time. For example, an ancillary service that, for example maybe a DR event might last six hours. Well, we can’t do for six hours, but there might be opportunities in the same day or around the same time that an ancillary service needs you for a ten-minute response or something to that effect. And I think there are different purposes for different programs that can cause them to overlap.

COMMISSIONER MC ALLISTER: Okay. But from your perspective it sounds like that’s okay and the system is kind of set up to deal with that.

MS. BEEHLER: Yes, depending on what you have responding to what, yes. And we usually preprogram ours. For example, we have so many -- at our super centers a lot of the time we have our daylight harvesting that takes care of most of our lighting during the day. However, on perimeter lighting we might have a little of that we can contribute.

But HVAC, I think, is a prime piece of demand response for many customers and it's a big one that we rely on.

COMMISSIONER MC ALLISTER: Great. Thanks very much, I appreciate your -- all your answers and your being involved here.

So, one final question and then I'll pass it off to everybody else.

For Target, let's see, Mr. Macdonald, are you still on the line? I don't hear.

MS. KILICCOTE: Anthony, are you still on?

MR. MACDONALD: Can you hear me now?

COMMISSIONER MC ALLISTER: Oh, there it is, great.

MR. MACDONALD: Yeah, I'm here.

COMMISSIONER MC ALLISTER: Great, thank you. So, you mentioned a mix of different kinds of contracts and partners that you work with and I guess I'm wondering the -- putting these -- putting the structures in place, you know, sometimes you're going to be talking with the system operator, sometimes through an aggregator. You know, how big of a deal or how varied, I guess, are the conversations around contracting and planning out the arrangement by which these resources get deployed?

And I'm really just trying to dig into how -- what the transaction costs are for you to really put the system in place by which you're -- you know, you're preplanning what dispatch is going to look like, and all the rules, and settlement, and all that kind of stuff. How much effort is that to put it in place at a given facility or with a given partner, like an aggregator?

MR. MACDONALD: Yeah, it can be pretty complicated depending on the aggregator or, you know, the local utility. But, you know, that's one reason why we partner with the aggregator so we don't have to worry about the settlement side or that.

But the contracting portion, itself, because it has to refer back to all of the program rules from the utility or the ISO, can be pretty significant.

We worked with one of our aggregators this year and it took us almost three months just to line up the contract and make sure we had the right systems in place, and the right stores figured out, and the bidding strategy ready to go before we could enroll in that market.

So, there was a lot of time, from our aspect, that is taken up in that and it's a lot of my time. So, the rest of my team kind of manages the day-to-day aspects and I'm responsible for more of the contract/program enrollments and program identification. So, the majority of my time throughout the year is working through those types of projects.

COMMISSIONER MC ALLISTER: Thanks very much. I'm going to let us move on because I think we're running behind.

CHAIRPERSON WEISENMILLER: Yeah, I'll try to ask just a couple of brief questions.

The first one is for the Navy, appreciate you being here. I did several tours down there with Jackie Pfannenstiel, when she was there.

MR. ROYBAL: Okay.

CHAIRPERSON WEISENMILLER: And I guess the two things that struck me. One, obviously, the Navy is SDG&E's largest single customer, so it's really important on the demand response side there.

Having said that, one of the things that she really was emphasizing was the micro grid as a way of really knitting together a lot of your demand response systems and I wanted to just see what's the status of that activity now that she's left?

MR. ROYBAL: Okay, great question. We are continuing with those efforts. So, in Metro San Diego, specifically, the Marine Corps Air Station, Miramar is making significant efforts and advances in their micro grid. Although I'm only speaking on the Navy's behalf, we do correspond with the Marine Corps.

CHAIRPERSON WEISENMILLER: Sure.

MR. ROYBAL: I can't give you specific status on that particular project but I know that they are continuing to make significant advances.

In the Metro San Diego area, for the Navy installations, we are also considering additional projects at each installation to identify, within each one of the bases in Metro San Diego, a specific area within the base that we can make into a micro grid.

So, at this point we haven't found it feasible, economically, to make the entire base a micro grid. We're targeting a specific area within the base that we're calling a critical area within the base, and making that a micro grid scenario.

So, we're making -- I guess it's not a real term, but we're coining it as a nano grid within the grid of the base. So, we're targeting a specific area within the base to make into a micro grid, and not the entire base because it's economically, at this point, infeasible.

CHAIRPERSON WEISENMILLER: Okay. One of the contracts we just approved last week was one geared at Pendleton, which will have a number of micro grids as part of the overall base, because they couldn't tie the whole thing together.

So, that may be some interesting experience for you.

The other thing that Jackie Pfannenstiel did was she put in place MOUs with UC Davis, the Lighting Center, and perhaps the Cooling Center, and also with NREL to provide technical support.

So, I was going to encourage you to get in place an MOU with LBNL's Demand Response Center as a way, again, of getting technical support from them.

We fund them, so does the Department of Energy, so there's a couple different ways you can get that technical resource you need. But it would be good to really, again, cement that relationship.

MR. ROYBAL: Okay, thank you.

CHAIRPERSON WEISENMILLER: Okay, in terms of Angie, one simple question. You talked about delays in regulatory proceedings. For better or worse, in the room we have the Energy Commission, the PUC and the CAISO so I'm just trying to clarify which of the three you're referring to. I think I know, but let's get it on the record.

MS. BEEHLER: Oh, maybe I better not answer that then.

(Laughter)

MS. BEEHLER: Well, I think it's been a combination of -- I think it's regulatory policy proceedings. And I have numbers that I can help you with on later, or however you want me to do that. I think some of it is the Smart Grid proceeding, some of it is providing direct participation in the markets.

CHAIRPERSON WEISENMILLER: Okay. Well, if you could just submit those for the record later, that will be great.

MS. BEEHLER: I will be glad to.

CPUC COMMISSIONER PETERMAN: This is Commissioner Peterman with the Public Utilities Commission. Audrey, President Peevey's Advisor, will also follow up with you afterwards.

Since you mentioned numbers, it's probably a PUC proceeding, so we can just stop there.

CPUC COMMISSIONER FLORIO: I think we could just plead guilty and get to work.

MS. BEEHLER: That's fine. I'll be glad to help, thank you.

CHAIRPERSON WEISENMILLER: Well, it could have been us.

MS. BEEHLER: You know what, our CPUC there works very hard and we're very thankful for what they do.

CPUC COMMISSIONER PETERMAN: You're not the first to raise that concern, it's okay.

MS. BEEHLER: Okay. I'll be glad to get with you later, no problem.

CHAIRPERSON WEISENMILLER: Okay, and the last question's for Veronica.

When Picker and I met with DWR on demand response, we basically heard the basic problem is staffing. You know, staffing capabilities, along with the human resources, along with the physical attributes.

And the one question that occurred to me afterwards is have you thought of contracting with a third party to actually run the ancillary services operation so you could bring in some pretty high quality talent, you know, without dealing with all of the vagaries of civil service that we all know and love.

MS. HICKS: Yes, they have looked at contracting in many aspects, just the power or the water, or both. And the challenge has been because the power and water operations are so intertwined, as well as coordinating with the Bureau, they felt that -- you know, it's one thing for someone to come and run the power side of the project, but you have to be versed in the water side to really optimize that power.

And so it's been difficult to find a resource or a company that could come in and operate the State Water Project for the water deliveries and bring that power expertise in, as well.

CHAIRPERSON WEISENMILLER: Well, given the difficulties of changing civil service, I suggest you keep digging in that area.

MS. HICKS: Will do, thank you.

CPUC COMMISSIONER FLORIO: Yes, I'm just curious, for any of the speakers, if there was one thing you could ask the PUC to do as quickly as possible, what would that be?

MS. KILICCOTE: Anyone on the phone who would like to respond to this?

MS. BEEHLER: This is Angie. I think just get the final rules in place of the decisions that are out there so we'll have some kind of security and knowledge how to move forward.

And we would love to help in any way we can there, but that would really give us some security in how to move forward on the decisions made, and the comments, so to actually put things in place to go forward in California.

CPUC COMMISSIONER FLORIO: Thank you. We will get on it.

MS. BEEHLER: Thanks.

CPUC COMMISSIONER FLORIO: Anyone else?

COMMISSIONER HOCHSCHILD: Yeah, this is David Hochschild. This is a question for the Navy. So, there's nine Navy bases in California; correct?

MR. ROYBAL: Correct.

COMMISSIONER HOCHSCHILD: And I understand the fleet is in constant motion, but just what are the bookends of the range of power, the load we're talking about from the ships that are connected to the grid?

MR. ROYBAL: Depending on the class of ship it could be as small as half a megawatt all the way to --

COMMISSIONER HOCHSCHILD: Okay, sorry, I mean in aggregate, all -- if you're comfortable with sharing that, I don't know.

MR. ROYBAL: So, I think your question is the aggregate loads for all the ships that are in our area?

COMMISSIONER HOCHSCHILD: Yeah, right, right.

MR. ROYBAL: I would say probably a ballpark would be -- and I say a ballpark because we do have visiting ships that aren't normally part of our inventory, if I'll call it that. So, we do have a lot of ships that are what are called home-ported and that's where they generally reside. But we also have other ships coming from other parts of the Navy and partners internationally, as well.

COMMISSIONER HOCHSCHILD: Uh-hum.

MR. ROYBAL: So, I would say as an aggregate for all the -- the four installations that do have ships, which is Naval Base Coronado, Naval Base San Diego, Naval Base Pt. Loma and Ventura, it's probably close to around -- the aggregation's probably, maybe in the order of 20 -- probably about 30 megawatts or so.

COMMISSIONER HOCHSCHILD: Okay. And in a super peak situation, just I understand, I mean could those be unplugged? I mean or do the air rules prohibit that?

MR. ROYBAL: The Navy's policy at this point is not to use ship-loading as the main demand response or the default demand response. It's a significant amount of effort for us to either plug or unplug the ships from the grid. Most ships take at least four to six hours to get off of their load onto the shore load. So, it's not a fast response time.

COMMISSIONER HOCHSCHILD: So that's kind of a worst-case scenario.

MR. ROYBAL: Right and in the past we have done that. During the fires, during a state or national emergency we have responded to that level of effort. But it’s not our go-to demand response scenario.

And former Secretary Pfannenstiel made it very clear in a statement that that is not going to be our policy.

COMMISSIONER HOCHSCHILD: Yeah, that makes sense. Thank you.

CHAIRPERSON WEISENMILLER: Yeah, some of it is that when ships are here it’s sort of a time to repair the ships and also for the people to get some recreation and training. So, basically, to just say, okay, let’s really disrupt that, you know, there are broader consequences in the training and other missions for the Navy, as opposed to just energy.

MS. KILICCOTE: With that, we’re going to conclude this panel about half an hour late.

Thank you very much for participating. Thank you for those folks who are on the phone.

COMMISSIONER MC ALLISTER: That’s the natural consequence of having the first panel. You guys did a great job.

(Applause)

MR. HUNGERFORD: All right, our next panel is the other half of the customer side of the equation, the aggregator perspective. And Mike Gravely, from the Energy Commission's R&D Division will be moderating this panel and he'll introduce the panelists.

COMMISSIONER MC ALLISTER: I'm going to also invite Heather Sanders to come up the dais, too, so we'll have all the agencies here represented and we're full up on the dais.

MR. GRAVELY: Thank you all. Mike Gravely from the R&D Division. And given the interest in this topic and discussion we've talked in our panel here about giving a four- or five-minute overview in three topics. One is what you do, the customers you work with and then, in general, what you do in California versus outside of California.

The purpose of this panel is to talk with aggregators who talk with large customers. So, the other way to bring large amounts of demand response in is to aggregate many customers under a single control and each of these four individuals represent companies that do that today.

So, in that interest I'm going to have each of them give a presentation and then what we'll do is allow the dais to ask questions and then go from there.

So, our first presenter is from EnerNoc. Mona Tierney-Lloyd has been in the regulatory business about

20 years. She has experience in DR and efficiency. She has an engineering degree from Penn State. And she'll talk to us about what EnerNoc does both inside of California and outside. Thank you.

MS. TIERNEY-LLOYD: Thank you, Commissioners for convening this panel and for your interest in demand response.

My name is Mona Tierney-Lloyd. I'm Director of Regulatory Affairs with EnerNoc.

And I wanted to share our perspective of how we provide demand response services, give you a little bit of an understanding of how we provide them inside of California and outside of California, and what we think could enhance demand response participation in the State.

Just to give you a little bit of overview of EnerNoc, we are an international company. We provide over 8,500 megawatts of demand response capacity to over 13,500 commercial and industrial customer sites.

We also collect real-time energy information from those customer locations. We receive about 23 gigabytes of data a day.

So, not only are we an energy management company, we are a data management company.

We have a Network Operations Center which is part of our name, EnerNoc. NOC is Network Operations Center, where we receive the real-time energy information 24 hours a day, 7 days a week, 365 days a year.

We do have a Network Operations Center in San Francisco and I invite you to visit our center when it's convenient for you.

We also have one in Boston and another in Brisbane, Australia.

These centers are redundant with one another so that we can provide demand response services anywhere in the world at any time.

Our NOC is also OpenADR capable, as well as all of the customer devices that we install in our commercial and industrial locations.

We are also a green button implementer. And part of highlighting all of those things is to indicate we are pretty technology-enabled, technology savvy in providing our demand response services.

As I mentioned, we do receive that real-time, 5-minute information into our Network Operations Center. That allows us to manage real-time operations during demand response events and also to gain information about the capabilities of our customers outside of those events. That's how our baselines are established and that's how measurement of performance is accomplished with that information.

We provide services across the spectrum in the commercial, industrial and institutional sector. That includes food processing and storage, grocery store chains, education, government agencies, including water agencies, agriculture, manufacturing, hotels, and resorts, and retail stores. So, we pretty much provide service across the gamut.

I also just want to indicate that we have a fairly high penetration of automated sites in California. Roughly, between 30 to 40 percent of our sites are, again, OpenADR compatible, but also auto DR enabled.

However, we think there's a role that aggregators play even in an automated market. And we maintain a high level of communication with our customers, not only to develop their curtailment plans, but to try to provide them with as much information in advance of anticipated events.

We're monitoring load levels in organized markets, like CAISO, and other markets. We're looking at temperatures. So, we try to give customers as much advance notification as possible, even if they are responding in fairly short periods of time.

Most of our -- or our exclusive participation in California at this point is through utility contracts, the Aggregator-Managed Programs.

We also participate in the Capacity Bidding Program, which is a statewide utility program, as well as the Base Interruptible Program.

We also have some dual participating customers that are in either CPP or PDP, as well as these other capacity-based programs.

Most recently we've had contracts approved with the utilities that call for 30-minute response and on a local basis. So, I'll just mention this is a brand-new requirement this year to be able to dispatch these programs either on a sub-lat basis, which is a CAISO market design component or on a local capacity area basis. And this is driving towards being able to count for resource adequacy on a local basis for the utilities.

While we have a fairly high percentage of our accounts that are auto DR enabled, we don't believe it's just set it and forget it with these customers. There's still, again, an aggregator role.

As Angie Beehler from Wal-Mart just indicated, there are times when these automated customers will have events that they need to override their participation, and then an aggregator would have to manage the loss of that load by replacing it with other loads.

And by doing that, the aggregator is the entity that's responsible for penalties for nonperformance, as opposed to the customers.

That's another thing that EnerNoc does relative to its customers, it insulates them from penalties or any costs for enablement.

We do participate in markets outside of California, PJM being the largest. I won't go into too much detail about recent events in the markets there. Susan Covino can give a lot more detail on that, but that we view as being a highly successful market design.

We also participate in the New York ISO, ISO New England, and Texas, in ERCOT.

In terms of other programs in the west, these are mostly bilateral agreements with the utilities that we have.

And I'll also just highlight that we are doing pilot programs to explore some of this renewable integration concern that we have in California. Some of these programs have been load-following programs with BPA, where the northwest has a lot of wind integration that they're trying to manage.

And we're also -- we have also recently signed a contract with Portland General Electric that would have a 10-minute demand response program, mostly fully automated.

But again, we provide ancillary services in other markets as well, spinning reserves in PJM.

And in our international markets we also provide the equivalent of spinning reserves.

We have under-frequency of resources that we provide in the Alberta market, where they have transmission constraints.

So, there's definitely the potential to provide a full range of demand response services.

One of the things that I would ask and have asked in other opportunities is that we provide a glide path. If we're going to make some significant changes in the structure of demand response in the State, that the rules are known well enough in advance and that parties have an opportunity to prepare to provide those kinds of services.

I would also suggest that we provide a range of services and not limit the opportunity strictly to a 10-minute automated demand response. Not all customers are going to be able to fit into that one size.

So, to the extent we give customers a range of options, I think that would be best.

We are -- there are some obstacles, I think. From a regulatory process consideration we have had the CAISO PDR opportunity that's been defined, but there hasn't really been participation at this point in time.

We're working through the regulatory obstacles at the CPUC in trying to get Rule 24 resolved. We've been involved in that process on an informal basis with the utilities. It's been a very good collaborative process.

And I think the other thing is to provide -- we've had a little bit of a start and stop effect with demand response, as well, where we have programs that terminate without replacement programs in place, so to the extent that we can provide that stability on the regulatory front, that's important.

If we have new programs that are approved, with a very short lead time for implementation, that's also caused a lot of consternation, especially this past year with the local requirements built into that. That's been a difficult process to implement very quickly.

The other aspects are, you know, we talk about the CAISO as an opportunity for demand response. I've expressed concerns about the economic viability of that in a market that has very low energy prices and no clear path to getting a capacity payment. That continues to be a concern.

And then also recognizing that demand response has operational characteristics that are different from a generator and if that demand is being forced to look and operate exactly like a generator including, you know, treating it like a point resource instead of a distributed resource that creates some inherent barriers for demand response, and limits the growth opportunity for it as well.

I think I'll stop there with my comments, and really appreciate the opportunity to be with you today.

MR. GRAVELY: Okay, thank you, Mona.

So, our next speaker is Ron Dizy from Enbala. And they're actually actively involved in the frequency response and the fast response DR, and he has presentations. So, they three of your presentations, just tell them and they'll change the slides for you, behind you.

MR. DIZY: Okay great, thank you.

MR. GRAVELY: So, just go ahead and go through, and we'll do that.

So, Ron, you can help us understand what your aggregator market is.

MR. DIZY: Thank you. Thank you for the opportunity to present some of our ideas.

Enbala's about intelligently balancing supply and demand through continuously connected customers.

The next slide, please. The power system needs real-time flexibility. When we talk about energy, and this may sound very basic but it's very important to make the distinction, obviously, a power system needs energy.

You can just tab through, I think, three of these.

It needs capacity and we spend an awful lot of time talking about capacity when we worry about power systems. It's the ability to meet any peak. And it is where we spend most of our time with DR.

But the third thing a power system needs to operate is flexibility. The ability to balance supply and demand in real time because electricity must be used the second it's created.

And that is the growing challenge that you have in California and, frankly, the growing challenge through most jurisdictions. I think you may have the distinction of leading and having the challenge.

And this is, I think, the real opportunity for demand side management, how can we use it to address this flexibility and not just the capacity, which is intensely valuable. It's great to use it there, it can also be used in flexibility.

The next slide. So, it turns out, you know, we have a lot about storage, too. There's actually a lot of inherent process storage in the grid. It is in the form of lakes and rivers for water pumping. Those lakes and rivers are very real storage. That storage gives me the ability to change the rate that I use power.

It's in a wastewater treatment plant where I've got dissolved oxygen. That dissolved oxygen is storage. It gives me the ability to change the rate that I pump into it.

It's in just every commercial building in the storage inherent in the building, and in the chilled water loop that, again, gives me the ability to vary the rate of consumption of power, and in cold storage facilities.

The challenge is, of course, each of these users of electricity, frankly, for them using the electricity's the most important thing and the flexibility is really a secondary point.

And so while they have the flexibility, how do we make sure it's available exactly when you need it?

And the key is we have to have aggregation or a fleet response, this ability to gather bits of flexibility and turn it into something which, individually, might not be reliable, but in the aggregate is actually reliable, robust and resilient.

The next slide. And so here's one approach. It happens to be ours. But we connect to a number of these loads all at the same time.

Just to give you a sense of speed, we would typically get about one-second data back from the loads. We're connected to their existing automation platform. In general, this scale of load will always have its own SCATA or automation platform. All we've got to do is add what we call a local communications panel to it.

And then that means we're also reusing the control mechanism, which is also very important. I've not yet met a water plant who will let us go in and just change their consumption. So, we have to work through the existing platform.

And then that optimization platform in the middle is essentially getting requests from the grid operator who says I need a little more power, a little less power in the power system, and is making a decision right now what's the best way for me to satisfy that both in terms of maintaining -- of answering that request but also, of course, in maintaining future flexibility. I'm going to have another request in 10 seconds, a minute, or whatever.

So, the next slide, please. We can pass through that. So, we are active in, I guess, five jurisdictions now, so we use this platform -- if you can tab once -- in PJM. We've participated in their frequency regulation market since November of 2011. We can kind of compete straight up against generators.

The IESO, which is Ontario's ISO, did an interesting experiment or is launching one, where 10 percent of their frequency regulation will come from alternative resources on a three-year program. That was competitively bid. We were one of the successful applicants and so we expect to be live there probably in the next month or two. The contract was signed in April.

And then two more, we've been using exactly the same platform to do direct wind integration in both New Brunswick and Nova Scotia. New Brunswick has been live since last September, I guess.

And the idea there is to break the wind integration problem into three pieces. So, one if the volatility inherent in wind when it blows and the second is what do I do with the wind when I lose it at a very inconvenient time, like during the morning ramp. And so can I use load control to soften the ramp? And so, we're doing that as well.

The next slide. And then we're just in the process of working with TVA right now to show how real-time load management can be used for a bit of peak shifting, a bit of supply/demand optimization. I can actually operate my generation fleet better if I've got the ability to alter demand in real time, and also AGC, in their case, so again frequency regulation.

We also did some work with the Oakridge National Lab. One of the very common questions is, well, just how much of this flexibility is out there?

I know that LBNL was also part of the same project, but we worked with the Oakridge National Lab on the commercial and industrial part of that project. And we found roughly 26 gigawatts in the U.S. power system. That's how much flexibility is available from large CNI loads. So, substantial enough, we think, to make a big difference.

We are not yet active in California. We just haven't found a way to participate in the markets here. So, we're very focused on these flexibility products versus capacity products. And I think the focus in California has so far been on capacity products.

If I have 30 seconds, I'll run through this quickly. Many people find this a helpful way to understand what do you mean by using flexible response or an aggregated response from loads?

That is a PJM, an actual PJM regulation signal. It's over about 6 hours and it gives you a sense of the volatility in the signal.

If you just tab once -- so, we now are adding a binary load. The binary load is reflected at the top, it's 1,000 kilowatts. You probably can't read the vertical axis, but it's in kilowatts.

And this is a load that happens to be constrained to only be allowed to be turned on and off once an hour, and it's got a 50 percent duty cycle.

The green line that's its reflection shows its regulation response, right, we usually talk about that from the point of view of a generator.

Just tab once more -- that's a second resource, same duty cycle, same limits. And you can see the aggregated response, you know, it sort of gets a little closer, but it's not very good.

Tab, say, seven or eight times. And so now we've just added eight -- one more time -- eight or nine binary loads have to be constrained to be turned on and off once an hour, 50 percent duty cycle.

I mean in general you would say these are not flexible loads, they are not going to be able to react. But you can see already that the response is pretty good.

If you tab a few more times -- and now we've added a variable resource so, obviously, you get better granularity from it and a network that has some of those in it will respond better.

If you tab a couple of more times you can see, now, that the individual response is aggregated into something that produces, you know, a pretty awesome response, even though individually these things would not be deemed as flexible.

And that's the value in having a fleet or aggregated response and what we think is important for you to pursue as you consider flexibility. Thanks.

MR. GRAVELY: Thank you.

Okay, our next speaker will be Kevin Evans from Johnson Controls. And his background, he was the CEO and President of Energy Connect before it was acquired by Johnson Controls, and he also has prior time with EPRI. Kevin.

MR. EVANS: Thank you. Again, one of the things I'll try and do is give a little bit of an overview of Johnson Controls. People are probably pretty familiar with what we do.

We provide both HVAC, as well as a number of other services to companies across the U.S. and globally, roughly about a $40 billion business, with about $15 billion focused in this energy space.

With that go ahead and click through that. One of the things we try and do and I think this is a fairly standard segmentation of the market, I think Ron has mentioned that we've spent quite a bit of time in the left-hand side of this, in the capacity side of things. People are fairly familiar with it. And that's where most of the revenues are in the demand response business today.

It's the place where the utilities have allowed for the aggregators to come in and share in that market, and we've seen some successes in that area.

I think, certainly, PJM has seen a lot of use of that market.

In the energy market we've had a number of starts and stops, I would say, and I'll give you an example of that in a minute, as we've seen that.

And what we're beginning to see is, again, more and more opportunity in what you might think of this very fast responding, 10-minute response kind of thing, 30 minutes of duration, as well as the frequency side that Ron has talked about.

All of those markets are markets that we participate in, that have technologies that will do that with our customers and allow for our customers, if compensated, or if installed in their facilities can provide through their York chillers or things of that nature.

Okay. So, one of the things I like to try and do is characterize the mismatch here. It's often, from a command and control stand point, which is what the grid was really designed to do, was ensure that we have reliability, predictability, availability and we need to quantify that load impact.

Absolutely critical, but I think the other side of this is to really keep in mind that the customer, after all they are the one that pays the bill, actually need to have flexibility, need to ensure that there's a minimum operational burden, that it's easy to engage and that there's actually a return on investment, or a return on performance, such as Angie mentioned.

If you can click one more time; one of the things that I believe the demand response providers, the aggregators sometimes referred to, can do is actually bridge that gap.

One of the things that we can do is by enabling technologies, in good communications with customers, in creative design and aggregation of those programs I believe we can meet those outcomes.

Next please. This is an example of a very interesting pilot that was started with the economic demand response in PJM. The graph, itself, is PJM and it shows very robust participation in a program and then it shows the program effectively going away.

This is exactly what you can do to demand response if you over regulate it, if you change the rules and if you continue to make it difficult for customers to understand. You will chase all the customers away, which is what we saw in 2008.

We had a very robust, on the order of a $50 million economic demand response program in PJM, which effectively disappeared for three years.

The FERC has come back and helped us try and get compensation correct and we've begun to see that system or that program being to percolate again, and begin to ramp things up.

The biggest issue for us is let's make sure that as we get the rules right let's get them right once, let's lock them down, and let's educate customers, as well as the public, and then let them go ahead.

This is an important point because I think one of the challenges we face is the pursuit of perfection is the challenge that really kills all demand response.

The idea that it is not a generator is important for us to keep in mind. And the idea that it will respond and perhaps we should design its response based on its characteristics, instead of its characteristics as seen as a generator.

Next please. This is a very good example of what a program, which is two programs put together, an economic demand response program and PJM, and layered on top of that is Act 129.

What you see on the vertical access here is effectively the use of megawatts. In this case it's a steel mill, using about 125 megawatts of power. And you can see their curtailment capability, they've reduced 75 megawatts at the flip of a switch for a period of six hours and we're compensated about $250,000 for that.

Click once. What you'll see is that actually provided about 55,000 homes with electricity. So, the ability to have these resources work well for us, communicate with them, plan, design these programs and implement, as they did here, and I think this is the first energy example in Pennsylvania, but the same happened in the Exelon or Picos world.

These programs are there, they can be done, whether you work with the utility directly -- the one requirement that they ask for in Act 129 is that the utilities had to work with aggregators, that they had to work through third parties to implement these programs and I think they did a very successful job in that regard.

Please click. So, I think in closing what I'd like to try and make sure that we see is let's design these systems for demand response which are more inform and motivate versus command and control.

Click. This idea of notification is absolutely critical. That steel mill that was able to cut 75 megawatts of load knew the day before that it was going to be an event. They knew approximately when to preplan that curtailment and shut down of an arc furnace, and did a very successful job over a long period of time.

By the way, they did that more than 100 hours during the summertime.

You can also see here that the more complex we make the measurement, whether it be guaranteed load drop, or whether it be firm service level, or both the important point here is let's not try and make it perfect. Let's get it close, let's understand its impact and then let's ensure that customers understand which rules they need to play with.

Last, again, a very important point, I think that Angie brought this up, is the carrot versus the stick. There's a natural predisposition that we want to penalize people for nonperformance instead of incent them for performance. And I'm just suggesting that the more that we create regressive penalty structures, the more that people will shy away from that.

After all, their primary objective isn't in this case to reduce energy, it's to build a product, it's to run the fleet of the Navy. Those things, penalty structures simply swoop the customers and aggregators try and mitigate that to some level.

Please click. Lastly, pay for performance with an annual minimum. The annual minimum design structure is one of make it worth my while.

One of the concerns that we see today in Texas is perhaps as much as $9,000-a-megawatt hour of compensation, but no guarantee that there will be an hour during the year.

So, with that in a mind a customer says, well, why bother? Maybe I'm going to get hit for it, maybe I'm not.

So, we need to have some sort of a framework in which a customer can go ahead and do that.

With one last click, so I guess what I would say is let's get started. Let's make sure for once we get the rules right, whatever right means in terms of the balance there it's absolutely critical because it's still going to take us 18 to 36 months, in my view, to provide a reliable, predictable resource for the grid. Thanks.

MR. GRAVELY: Thank you.

And our last speaker today is John Rossi from Comverge. He was the co-founder of Comverge and also, prior to that, he spent about 25 years with Bell Labs doing research for AT&T and Lucent Technologies, so John.

MR. ROSSI: Thank you very much for the invitation today.

Click please. Comverge provides both residential, and commercial and industrial demand response. Today I'm going to speak from the residential perspective.

Our background on the residential side is that we have over 5 million devices in the field. Recently, we've been participating in programs in a turnkey fashion or in a pay-for-performance fashion.

So, over the last three years we've recruited about one and a quarter million customers into these programs for direct load control.

We've installed up to 220,000 devices in a single year. And, of course, this is scalable depending on the programs that we're running.

Last year we contributed or had control capability of contributing 32 gigawatts of peak energy.

In our marketing capability we've achieved penetration rates in a territory of over 30 percent of the addressable market. That would be the market of customers who have HVAC, central HVAC.

Over the course of time we've worked with all three of the California utilities in some way, shape or form.

The next slide just illustrates that we do different kind of programs with different types of technology.

So, we have a turnkey direct load control program where we're hired by a utility to provide all aspects of the program from marketing to installation, to M&V. And we're paid a fee for doing each of those services.

We've also been a pioneer in price-responsive programs, critical peak pricing. We've had a critical peak pricing program at Gulf Power for a decade now.

One of our key areas of contribution is in pay-for-performance direct load control. In these types of contracts we're paid for the megawatts that we provide to the system when requested by the utility or the ISO.

We've also had some experience in real-time pricing programs where we used an existing direct load control program and gave the customer an option to opt to have us control automatically if a price reached a certain threshold.

So, those are the type of programs. And you can see that we've worked with all types of automation end points, thermostats, air conditioning control switches, or pool and water heater switches.

We also work with third party automation, if the need arises.

Next. So, I'd like to talk a little bit about the characteristics of the residential market and make a point as to why it's worth time to invest in this resource.

First of all, and maybe foremost, the residential air conditioning -- residential and small commercial air conditioning is a significant driver of the system peak.

If you have a program that attacks this peak, you can get incremental capacity from day one of the program. We can recruit customers and start installing, and you build the resource as a function of time.

The other thing about the resource is, obviously, it increases with the temperature. So, as the peak increases, so does the resource.

Residential demand response is and always has been 100 percent automated for fast dispatch and reliability.

It's also a resource that's load only, there's no generation involved.

It's available for many hours in a year, well in excess of 50 hours. We've run programs for approaching 100 hours. The technology and the concepts have been proven for years across the country.

One other thing to keep in mind about a residential program is that it has a higher initial cost versus commercial and industrial programs because we're dealing with -- we're getting megawatts a kilowatt at a time. Whereas CNI, you can get many tens or hundreds of kilowatts with one customer.

But what we find is that over time the residential programs actually are less costly to run.

The residential and small commercial programs are also substantially less expensive than a peaker when you have comparable operational capabilities.

Also, I'd like to point out that dealing with residential and small commercial demand response has strong potential synergies with energy efficiency, so that's something that should be exploited.

So, let me give you the benefit of some of the things that we've learned about residential programs, having run them for many years.

One that I think will surprise many is the first point here, that given a choice between a direct load control switch on an air conditioner compressor outside the house and a programmable thermostat inside the house, the majority of customers will pick the switch over the thermostat.

And the reasons for that are twofold. One is, probably most important you don't have to have someone come into your house to install the thermostat. And second, many people are happy with the thermostat that they have and they're not interested in getting a new one.

So, for those reasons what we find is that the majority of people, given a choice, the same program incentives will choose the switch.

The other thing that we've learned is that if participants in the direct load control program can opt out easily, they will.

We had one program where we had programmable communicating thermostats. One of those thermostats allowed instantaneous override at the thermostat and the second we required the customer to call the call center and we would opt them out of a control event.

And what we saw was that that added step of having to make a phone call reduced the actual opt-outs during peak events from over 30 percent to less than 1 percent. So, that little extra step gets people to not opt out of the program.

I'll comment that critical peak pricing programs has fewer opt outs because the customer has that economic incentive, but variable pricing is a harder sell to customers because it's more complicated and it changes the basic way they pay for energy. It's a harder sell than direct load control.

One very important point that we've learned from marketing these programs over the years is that too many options cause confusion and actually inhibit sign up. So, if you give a customer a range of programs, a range of possible cycling strategies, et cetera, you'll actually inhibit their signing up for any program.

The last point here is that our residential programs, through two utilities, have been qualified for WECC ancillary services, 10-minute response, and at guaranteed quantities.

So, last let me give you some of our recommendations on the residential side.

We believe that the readily addressable market for residential programs is between 10 and 25 percent of the addressable market.

We say this after having recruited customers through programs across the country.

And given that this is the case, if you want to get fast response programs and resource adequacy grade programs, you should make it such that you recruit into the highest value program first.

Because as I said in the previous slide, if you have multiple programs out there, customers are going to pick one and that's the end of it. They're going to say, well, I did my part and they're not going to move to the program that you most desire them to be on. So, you have to think of this in advance.

So, start with the program that's of most value and then incrementally add programs over time because you have to do this anyway, because different customers respond to different types of marketing.

To do this, you obviously have to plan the rollout in advance. And because these multiple messages add confusion, so you have to say I'm going to focus here, and then I'm going to move over here, and it has to be done in advance.

And through all of this and probably most importantly customer education is important, but it has to mesh with the goal that you're trying to reach.

Also, we would recommend that since this is a very specialized area to run and recruit customers into these programs that this be a third-party-outsourced, pay-for-performance model.

And we would advocate pay for performance at all levels. The current programs in California have very lucrative fixed payments to customers which affect the cost-effectiveness of those programs.

We don't believe that that's necessary, that you can design a pay-for-performance incentive and still get customers onto the programs.

And we also believe that, certainly, the curtailment service providers should also be paid for performance.

And we believe that regulations should be in place that provide a mechanism to value the synergy between energy efficiency and demand response at the residential and small commercial level. Thank you.

MR. GRAVELY: Thank you all. Given the time, so are there any questions from the dais?

COMMISSIONER MC ALLISTER: Well, I could come up with a ton of them. I know we're really pressed for time and Suzanne is, oh, my God, he's going to do it again.

So, I'm going to refrain and really see if others on the dais want to ask questions. I want to, first, just thank you all for being here because, really, you're the leaders in this area in a very real way and I want to really encourage you to keep, and I know you will, keep plugged into what we're doing here. I mean this is really the first step and I'm really going to depend on your knowledge and understanding of the customer, the value proposition, the needs of the system to sort of figure out how to get this right.

So with that I'll pass to anybody else on the dais who wants to ask some questions.

CPUC COMMISSIONER FLORIO: Yeah, I have a question. I mean we're dealing with a lot of actors here. We have, in most places, including California, a system operator, we have the aggregator, we have the utility, we have the customer.

And, you know, based on your experience what is the most efficient institutional arrangement among those different actors? You know, is there one model that stands out to you as the best to work with or, you know, are there just a variety of different models and you deal with what you get?

MR. DIZY: I'll take a crack at starting. I think there's a very important role for the ISO to start. And the key thing there is to just find the products that you want.

It's very easy to get caught up in this notion of, you know, direct load control, oh, so now I've got real-time reaction.

I think the single factor that gets underestimated the most is how often are you going to want to use it?

So, when you define what the products are, are they going to have to be bi-directional, meaning does the load actually have to consumer more and less sometimes, like a regulation product, or are you okay with it not doing that?

Is it going to be energy neutral or not?

And then, you know, as I say, how often?

So, when we think about rent products that you're going to want to have, those may be called tens, hundreds of times a year.

If we take the extreme and go to frequency regulations, if you work it out, every four seconds is 7.88 million times a year.

So, I think it's crucial to define what you want first.

The second thing, you asked what actors. I really think there is an important role for the utility in carrying the message of the importance of these programs and I think that will increase.

I think it's very clear that the average consumer probably gets DR. They get having enough of something because that's a very common construct.

The notion of flexibility you shouldn't underestimate, right, that idea that there's actually enough power in the system it's just not moving fast enough, because I don't think the average person gets the destructive nature of -- or, you know, needing to use it the second it's created.

And then, you know, so I think there's a role for all of the actors. I think there's a leadership role for the CEC and the CPUC, but with heavy, heavy work from the other actors involved.

MS. TIERNEY-LLOYD: Commissioner Florio, I guess an observation would be there does seem to be many layers here relative to other markets, with all the entities that you just expressed.

However, I think the market design and the way that this market developed is very different from other markets, as well.

And we started with a retail market structure, developing the resources there, so aggregators through utilities, and then layered on top of that a CAISO opportunity.

So, we think for probably the foreseeable future all of those entities are probably going to need to continue to be involved because we are transitioning into what this new market is going to look like. And especially because of the economic, lack of economic incentives for participation it's our perspective that even if we complete the Rule 24 process expeditiously, the realistic opportunity for participating in the wholesale market in the near term is still probably going to be through these utility contracts just because of the capacity concerns.

But in other markets, for example, like PJM, it is a much cleaner, straight forward process of, you know, aggregator participating directly in that market.

And then layered -- I'll just add one small -- and layered on top of that utility programs. So, it really started from the reverse position that we're starting from.

MR. EVANS: Yeah, I would take the -- would support the same thinking. I guess there is clearly here a structure which we have today, which I would characterize as retail programs.

Certainly, in PJM it's more of a wholesale market that seems to be effective in many ways. But that said, we also saw through Act 129, state-based programs worked very effective.

I guess the one thing I'd introduce that is somewhat maybe a different thinking is that while we may need to design a California unique solution, for customers like I have across the U.S. and around the world, Angie from Wal-Mart and others, the multi-jurisdictional customer, how they buy power, why can't they buy power like they buy telecom today? And how might we evolve that over many years in order to allow them to source power.

Perhaps, as we know in some cases, customers such as Safeway get their own gas, convert that gas to electrons, with an off-take agreement and supply their own stores.

So, I think we just need to think beyond the current design and think about how we might enable a customer to buy national power, allow for that to be paid for and distributed across its footprint.

And I think that might help put the customer in advance or put the customer's centric view in mind.

MR. ROSSI: From a residential program perspective, given the significant up-front investment the best structure is a long-term contract, which is probably more conducive to a utility contract.

For example, there's been no residential demand response that's been provided by a third party into the PJM market because the visibility isn't long enough to -- and the stability isn't long enough to make the investment comfortably.

COMMISSIONER MC ALLISTER: Yeah, that's interesting.

CPUC COMMISSIONER FLORIO: One thought I had, as I understand the aggregator-managed programs in California, and I don't claim to be an expert, you're sort of selling a bundled product to the utility. And one thought I had is maybe as we move forward we might want to unbundle that so you have a capacity contract with the utility but you sell ancillary services, energy, whatever directly to the ISO.

Does that make sense or am I just making it more confusing?

MS. TIERNEY-LLOYD: I guess one thought on that is -- and this has been the tension between the retail programs and the CAISO market, which is who has the ability to call the resource and dispatch the resource?

And the utilities see the value of the programs not only to address system concerns, but also to address local concerns.

So, my immediate thought to your proposal, which is an interesting proposal that I'd like to spend more time thinking about, is that if the energy and the ancillary services are being dispatch essentially -- or bid by the aggregator, that takes some of the control away from the utility who owns the capacity.

So, that's an initial thought.

MR. DIZY: I can add a little bit to that. I mean PJM has gone some ways to thinking about this because the capacity market predated the idea that loads might participate in some of these flexibility products, like frequency regulation.

And I think it's absolutely worth thinking about when you're at the front end of the rulemaking because it's definitely harder to fix them after the fact.

I think what you want to think about is the idea that there could be more than one aggregator associated with the same customer because they will offer different products and services.

And that will be true over the future, right, as people invent new things and new ways for loads to participate in the power system.

Number two, you want to think about which products do you think are compatible with each other and which ones aren't?

So, you know, DR which is called -- or let's call it traditional capacity DR that might be called in, you know, a few tens of hours a year versus some flexibility products that might be called in hundreds or thousands, you have to decide if you believe those are compatible products or not, i.e. can a customer bid both?

And I think if you put clarity into what those rules look like then you can absolutely have people participate in multiple ways as best for them.

Another piece of that is sub-metering, so allowing a load to subdivide its actual assets. We tend to think -- our thinking tends to stop at the utility meter but, you know, I'll submit to you you've got a large factor. It's got, say, 4 megawatts of environmental and very flexible load that they can't turn off for four hours or five hours, but it's got flexibility, and you've got other load at that plant, production lines that you don't want to touch very often, but when you do you're willing to do it for, you know, five or ten times a year, for four hours at a time you actually do want to shut it off.

So, they're different. So, allow those loads to subdivide themselves and you'll get much higher levels of participation.

MR. ROSSI: I think that the idea has merit and should be pursued further. One precept that I would say is that the capacity payment be viewed as an insurance payment and, hence, you can do energy in other programs and still get the capacity payment, it not be inhibited as it is in some jurisdictions, I might add.

MR. EVANS: Yeah, the one last piece that I would add is the fundamental question of who owns the customer and that is not clear in the programs that we have.

I think I would characterize it I own my customers, yet those customers are actually represented, I think in the PG&E and SDE structure, as their customers.

Putting us at odds with the utilities where who owns the customer is probably not the right design.

COMMISSIONER MC ALLISTER: Could I just dig into that a little bit? So, in PJM, you know, I get the historical differences there.

But what do the utilities, you know, the load-serving entities feel about their customers having a direct connection with the ISO, with PJM?

MR. EVANS: Yeah, there's a number of different designs, depending on the state. So, in some cases you have, as in Dominion, for the most part a fairly vertically integrated where they own both the LSE and EDC roles.

In other places, like Pennsylvania, it's actually split. So, you could have the LSE, they could buy power from most anybody, yet it's still delivered through PICO, or First Energy, or what have you.

So, it's a little more of a disaggregated market in that design.

In all of those cases, though, what we do is represent the customer as a aggregator and then present that customer's load as an asset.

Then the verification of that is through PJM and then back into the EDC so that it ties out to their bills.

COMMISSIONER MC ALLISTER: So, this is all extremely helpful.

I'm going to sort of make a last call here. It looks like Commissioner Peterman wants to ask another question.

And I'm hopeful, I see Joe Eto back there nodding and so I think it's probably a good bet that we're going to dig into this structural issue later on in the day.

But I really feel like one of the key issues here is how we can -- is what market constructs, you know, construct or constructs are actually going to convey a clear value proposition to the customer so they opt in to do something, right. Whatever the structure of that ends up looking like that the customer has to feel motivated to make that decision and allow those things to happen on their facility, or at their home, et cetera. So, hopefully, we can sort of keep our eyes on that prize.

CPUC COMMISSIONER PETERMAN: A quick question. Apologies if you touched upon this earlier in presentations.

With regards to the customers that you're aggregating in PJM, to what extent are these customers fulfilling their DR obligations by switching to backup diesel generators?

And then to what extent is that switch being calculated or considered as a part of the State's overall greenhouse gas policies?

MR. EVANS: Right, I'll address that. So, roughly 10 percent of our generation is currently permitted diesel backup generation. Another, roughly another 10 percent would be based on other forms of backup generation, including what might be battery storage. So think of it as other than curtailing of load, it's behind-the-meter generation, if you will.

So, roughly 20 percent of our loads overall, half of which is diesel, all of which is properly permitted under the EPA's regulations. Which, I might add, that sometimes are at odds with the state regulations, which can often cause some difficulties for PJM.

So, we have that problem today. As an example, in New Jersey you're only permitted to use that generation if, in fact, there's a voltage reduction when in fact there may be an event called with no voltage reduction.

CPUC COMMISSIONER PETERMAN: And that 10 percent, is that your policy, is that the PJM's state policy?

MR. EVANS: No, PJM can speak to theirs. I think their number is closer to one-third, but I'm not certain about that.

CPUC COMMISSIONER PETERMAN: Okay, but that's just your company.

MR. EVANS: That just happens to be the makeup of our customers.

CPUC COMMISSIONER PETERMAN: But it's not limited to 10 percent.

MR. EVANS: Not at all.

CPUC COMMISSIONER PETERMAN: Okay. Others, Mona, did you have a comment on that?

MS. TIERNEY-LLOYD: Yes. We use backup

generation to the extent, again, that it's permitted and compliant with either state or EPA regulations, which currently limit dispatch to 60 hours per year for emergency purposes.

And the number that we have in our portfolio, in PJM, I think is somewhere in the 15 percent range.

MR. DIZY: So, Enbala's not a traditional demand response provider, so it's not capacity, it's flexibility, but 100 percent of what we do, actually everywhere, is done when modulating load.

CPUC COMMISSIONER PETERMAN: Okay, thank you, that's helpful. That's just a point I want to make sure we keep in mind for the overall greenhouse gas impact since that's the whole point of doing some of this in the first place.

COMMISSIONER MC ALLISTER: Yeah, I think that's a really core reason behind why my thinking is, at least, that we're going to end up with a California solution and the air quality issues, and our history of regulation in that area is going to be different from anywhere else. And so we've really -- the makeup of these products has got to take that into account. But it's a great point and that other experience is really interesting because, you know, it has to do with what the customer needs to meet their load requirements and keep their business going. So, I think backup generation often can do that.

So, are there any other, maybe going once, going twice, any other questions on the dais?

I'll pass it back to Suzanne and it looks like we're probably on track to reconvene at quarter of 2:00.

MS. KOROSEC: Yeah, let's try to do very promptly at 1:45.

COMMISSIONER MC ALLISTER: So, I hope you're not all too hungry but thanks a lot, that was very, very good discussion.

(Off the record at 12:42 p.m.)

(Reconvene at 1:50 p.m.)

COMMISSIONER MC ALLISTER: All right let's see if we can get moving here. It's ten of 2:00 everybody. Let's see if we can get going. We've got a lot of ground to cover today and we got a good start this morning and, hopefully, we can keep things moving forward through the afternoon.

MR. ETO: Good afternoon. My name is Joe Eto. I'm a scientist at the Lawrence Berkeley National Laboratory --

MS. KOROSEC: Folks could you please sit down.

MR. ETO: -- where I lead the Electricity Markets and Policy Group. Among other things I lead R&D

demonstrations and electricity reliability technologies, including demonstrations involving the residential AC load control fleets of both Edison and PG&E and demonstrate implementation of non-spinning reserve in the California ISO, in a simulated version of the California ISO market receiving dispatch signals from the ISO.

I'm very pleased today to moderate this panel. I think we've heard this morning that market structure matters and so I think it's very appropriate that we hear perspectives both from the Federal level, as well as our brethren ISO's and RTO's across the country about how those structural issues play out and the way that demand response has developed, what their plans are for future development, and what are some of the challenges that they see.

I've asked each of the speakers to speak broadly to these topics, really as a way of introduction. I know that the panel is very -- that the panel of Commissioners is very interested in this topic and so I'd like to maximize the amount of time for your questions and interaction with our panelists.

So with that let me start by introducing MaryBeth Tighe. She's the Senior Technical and Policy Advisory to Chairman Jon Wellinghoff with the Federal

Energy Regulatory Commission. She advises the chairman in his consideration of policy matters and in particular regarding his high priority for designing wholesale markets that operate and plan efficient, and cost-effectively and reliably to integrate demand resources, renewables and other emerging technologies.

MaryBeth has over 30 years of energy industry experience, including stints as a Vice-President and Director for Regulatory Affairs for Statwell Energy and Amerada Hess.

And back when I met her she was Director of Integrated Resource Planning at the Maryland Public Service Commission.

So, thank you very much MaryBeth for joining us.

(WebEx operator interruption)

MS. KOROSEC: All right, we're looking here to see if we've still got her online. MaryBeth, are you there?

(WebEx operator interruption)

MS. KOROSEC: It looks like MaryBeth may have lost her connection, so we'll try to get her hooked back up again.

So, maybe we can introduce some of the other panelists while we're trying to get her back on.

MR. ETO: Okay, that's fine. Let's go to our second panelist. I'm very pleased to introduce Suzanne Covino. She is a Senior Consultant for the Emerging Markets Program at PJM Interconnection. She previously served PJM as a Manager for Demand Side Response. And she's formerly also been involved with the New Power Company as a Director of Government Affairs, and also, a Director of Government Affairs for Enron, covering the mid-Atlantic and northeast regions of the U.S.

Suzanne.

MS. COVINO: Thank you very much. And thank you very kindly for your invitation to share a little of our experience at PJM with you today.

I heard earlier the question, well, we look to the east and we see 8,500 megawatts of demand response actually out there doing capacity, what's your secret? And the secret is two words, the capacity market.

And, more specifically, the reliability pricing model that our stakeholders put in place in the FERC back in 2007.

It's a forward market, three years forward, so planned resources can offer in and make sure their costs get covered and have some time to aggregate load reduction capability.

And it's locational. It shows generators and folks doing energy efficiency and folks doing DR where we need it the most.

These markets, however, are dynamic. Right now over 95 percent of all the revenues paid to curtailment service providers by the wholesale market of PJM are for capacity?

Will it always be that way? I sincerely doubt it. It changes. Markets are dynamic, prices change over time as supply leaves or load increases. So, it's important to keep that in mind when you're looking at market design issues.

In our markets there's a function and it's called curtailment service provider. Competitive aggregators can do that function in some of the states. Utility companies can do that function. Load-serving entities can do that function.

Who gets to do it is up to the state regulatory commissions and we have 13 of them, plus the District of Columbia, that we work with.

We have a relevant electricity retail rate authority, or a state commission, or a muni, or a co-op and they decide who gets to be a curtailment service provider in PJM's wholesale markets.

So, we have a wide variety. We have some states, like Indiana and Kentucky, they tend to favor having their utilities perform the curtailment service provider function.

But we have other states like Maryland, New Jersey, Pennsylvania, Ohio, Illinois, the District of Columbia and Delaware who are all part of MADRI, the Mid-Atlantic Distributed Resources Initiative, and they're rather keen to have competitive suppliers operate in their markets to a greater or lesser extent, again depending on their own policy preferences.

So, we've learned over time how to manage and try to provide as many options as we can for load reduction capability to come into our markets.

I guess the other important sort of market structure question would be we've built the reliability pricing model on a fairly firm foundation.

At PJM, we've been at this demand response for about ten years. And way back at the beginning, the 2002 timeframe, we worked very closely with our stakeholders and responded as best we could to the policy directives from our regulator, the Federal Energy Regulatory Commission.

What we found was by integrating demand response into the very fabric of our markets on June 1st, 2006, I think we really lit an important match under a lot of curtailment service providers. No more programs, no more add-ons, no more three years of this and two years of that.

Demand response joined the market in an integrated fashion, going forward for once and for all. And we saw results. Did they come real quick? No, it took some time. But the message was out there that demand response was an integrated part of our markets.

By August 18th of 2006 EnerNoc had provided us with the first demand side resource in our synchronized reserve market.

Notice we had to change the name of it from spinning reserve to synch reserve.

And then, as I think Ron mentioned a little bit earlier, his team had the distinction and honor of being the first CSP to provide us with regulation, frequency regulation November 21st, 2011.

So, again, capacity market, I think someone earlier, on an earlier panel said define the products. Define what you need and then get out of the way and let folks come in and do what they do so well, think up new and innovative ways to solve problems and provide services.

Now, one other thing I want to make you aware of and that is more recently we've developed still another option for load reduction capability to participate in our markets. It's called price responsive demand.

And essentially what it does is it accounts for load reduction capability on the load side of the market, rather than on the supply side of the market where we've more or less shoehorned it in for the last ten years.

And the key point behind this, beside the fact that we've got this option out there, market rules ready to recognize its benefits, is the fact that we did it in collaboration with state regulators.

So, we do routine visits with all of our state commissions and sit down and talk with them about what's on their mind.

One of those visits to Ohio, Commissioner Scentella said, you know what, I got these utilities coming to me and they want a decision right quick on how much I'm willing to approve their deployment of advanced metering infrastructure. I've got them breathing down my neck because there's stimulus funds out there that may be available for them. We've got to make the decision quickly.

But I'll be danged if I'm going to approve this thing and not have responsive customers, decisions implemented, recognized and accounted for in the wholesale market.

And we said you know what -- and this is we, Andy Ott, our Senior Vice-President for Markets said, you know what I've got some concerns, too. If you deploy these resources and people begin to change their behavior, my load forecasts are going to be off because they're all based on history. History when there was no AMI, when there were no dynamic retail rates to send messages to customers about when to reduce their usage.

So, I've got worries about this, too. We've got to talk about this further. And we did, and our stakeholders did, and our board supported it.

And now we've got the market rules sitting there when the retail side of the market is ready to embrace it and move on. And, hopefully, with some of the exciting things happening right out here in Silicon Valley, around the Smart Grid, it won't be long before we actually begin to see folks venturing into and taking advantage of price-responsive demand. Thanks.

MR. ETO: Thank you, Susan.

I'm told that we have MaryBeth on the line. So, MaryBeth if you're ready, we'd love to hear from you.

MS. TIGHE: I am here. Good afternoon. Are my slides showing there?

MR. ETO: Yes, they are.

MS. TIGHE: Thank you very much. Good afternoon, I'm MaryBeth Tighe. The Federal Energy

Regulatory Commission, or FERC for short, regulates the rates, terms and conditions of sales and transmission of electricity in natural gas and interstate commerce. And FERC has, for several years, held the view that demand response resources can help operate the electricity grid in wholesale markets more reliably, efficiently, and cost-effectively to the benefit of all consumers.

The Commission has worked to ensure that wholesale market designs and rules for planning and operating the transmission system are ready to provide access to these resources on a fair basis.

In the past 15 years FERC has approved various utility proposals to call upon customers to reduce demand on a few hours' notice during critical conditions or emergencies on the grid.

Usually, these customers are asked to reduce only a few times a year, for a few hours, as a last resort for reliability.

But with the rapid evolution of communications and consumer technologies, FERC recognized that demand response resources are capable of acting more often and more quickly than only in emergencies.

So, beginning with Orders 890 and 693 in 2007, and Order No. 719 in 2008 the Commission formalized, through rulemaking, that demand response resources could be used as a tool to operate the grid more efficiently and reliably and to plan for a reliable transmission system.

If possible, are you able to move to slide 2? Thank you.

In 2009 FERC staff published the National Assessment of Demand Response Potential. The assessment found that demand response had the potential to reduce peak demand by 15 to almost 25 percent of peak load nationwide by 2019.

The potential for California was similar and it was estimated to be from 7 to 17 percent of peak demand in 2019, depending on the information and technologies offered to help consumers manage their electricity usage.

In a separate survey of all market participants in 2012, FERC staff found that advanced metering in the U.S. had grown to 23 percent of all electric meters and that the reported demand response capability nationwide had grown to 72 gigawatts, or about 10 percent of peak demand.

In this particular survey demand response capability is the actually installed demand response capability to reduce when called.

While 70 percent of California customers had some form of advanced metering by 2012, the report found that demand response capability was at about 200 megawatts.

Could you proceed to the third slide, please? Thank you.

Today over 4,000 megawatts of demand resources participate in wholesale energy and ancillary services markets, and about 18,000 megawatts participate in capacity markets, with participation expected to increase in coming years in all of these markets.

Typically, participation involves integrating price bids, bids from demand response resources into the clearing of the respective market in lieu of using more costly resources.

This slide shows the market opportunities open to demand resources today in the various markets in RTOs across the country.

Recently FERC has taken steps to provide fair access to markets that make the investment in demand response capability more attractive to customers.

In Order No. 745, regarding demand response compensation in organized wholesale energy markets, the Commission determined that when an RTO dispatches demand response resources to balance supply and demands in its energy markets, and it’s cost-effective to do so, then the demand resources should be compensated at the market clearing price.

Second, in Order No. 755, regarding frequency regulation compensation in organized markets, the Commission directed RTOs to pay resources that can quickly and accurately respond to the operator's signal to correct frequency deviations to pay them in accordance with their performance.

Maintaining frequency within a tolerance band is crucial to the reliable operation of the transmission system and is called frequency regulation service.

Demand response resources may be able to respond very quickly and accurately, and will be paid with their performance once compliance with 755 has been completed.

Also through this service demand response will help to integrate variable resources into the grid.

Last June the Commission proposed to extend this pay-for-performance approach to frequency regulation into areas outside RTOs.

And then third, the Commission recently reiterated in Order 1000, that non-transmission alternatives, such as demand response resources, may be considered in transmission planning.

I appreciate the opportunity to discuss FERC's market initiatives and policies with regard to demand response and I look forward to your questions.

MR. ETO: Thank you very much, MaryBeth.

Next, we have Joel Mickey. He’s the Director of Market Design and Development for the Electric Reliability Council of Texas, or ERCOT. His team is tasked with providing technical and business expertise in support of stakeholder internal market monitoring and PUC activities related to strategic market design initiatives.

Currently, this includes resource adequacy issues, demand response, pilot projects such as fast response to regulation service, and weather-sensitive demand response.

Mr. Mickey’s previous roles at ERCOT have included Director of Grid Operations, Director of Wholesale Market Operation Systems, and Manager of Market Operations Support. Joel.

MR. MICKEY: Well, thank you for having me here today. I thought I’d talk a little bit about some of the DR programs we currently have going on at ERCOT, some of the issues surrounding those programs and what we’re working on next.

With that, we have several different types of load resources participating in ERCOT currently. One is called load resources and they provide responsive reserve ancillary services.

We procure 2,300 megawatts in ancillary services each day for a responsive reserve service. We limit 50 percent of that to be provided by load resources and every day we get pretty much that whole 50 percent from load resources.

These load resources are typically large industrial loads. There’s 214 that are registered and with a total combined capacity of 2,650 megawatts.

Load resources are dispatched during emergency alerts so they are -- it’s only when we’re in an emergency event when they can be dispatched, not just during a normal business day.

We also have controllable load resources. That was talked about a little bit this morning. These are sophisticated control systems that can actually move up and down to a signal. We only have one of those right now and it’s roughly 20 megawatts.

Then emergency response service is another ancillary service. It’s either 10 minutes and now we have a 30-minute pilot going on to -- these are deployed during emergency events, also. Again, usually mid to large commercial/industrial customers and they’re procured on a three-month contract cycles. So, four times a year we procure for the next three months on these services.

And we've broken down the hours to try to -- instead of doing it for the whole 24-hour period, we tried to find a way that -- like the Wal-Marts and the Targets, you know, have air conditioner load during the peak hours of the day, so we carve that out as one time period that they can participate in.

There's other industries that can participate all day or on the weekend, so there's different time periods that kind of help encourage participation.

And then a lot of them told us if you can give us 30 minutes' notice, instead of 10 minutes that they would have more that they could offer. So, we're doing that pilot right now.

So, in sum, we have about 1,400 megawatts of loads providing responsive, we have 550 megawatts of ERS. We also have some legacy transmission distribution programs, it's about 240 megawatts. So, roughly, there's 2,000 megawatts and with our system peak it represents about 3 percent of our load.

Also mentioned this morning that -- it's not a program that we have, but the way our tariffs work in Texas, it's called 4CP. I don't know if you guys heard that this morning, but it stands for 4 coincident peaks. It's how the loads kind of pay for -- how their capacity is calculated for their transmission capacity costs.

Well, that rule actually incents demand response because every -- every large industrial load will try to figure out when their highest peak's going to be and they'll try to curtail it, and that will set their rate for the rest of the year.

So, it's a large factor in demand response in Texas. The only problem is we don't know how much it is because we don't know what their peak would have been, but it does at least keep them down.

We also have some -- you know, Texas is a de-regulated retail choice for about three-fourths of our customers. And we're not responsible for how the retail rates work in those areas.

But we are starting to see some types of critical peak pricing come to play. Again, we're not in control of that so we don't know how much it is. We're doing studies and surveys to find out how much of it is out there to try and keep track of that.

Unfortunately, when you have those kind of products, either the 4CP or the critical peek pricing they're what we call passive response. And over time those passive responses get built into the load forecast so you don't really know how much you're getting, but you might see a difference between what you're anticipating the load on the grid to be and what it actually was.

And we also do voluntary appeals. Again, we don't know how much of that is baked into what happens, but we do -- have improved our Twittering and our outreach to tell people when we're having a critical day ahead. And with a little bit of warning, a little advanced notice we're getting a little bit more demand response that way, also.

In Texas we've had a long discussion on whether we should have a capacity market like PJM has, which definitely will bring a lot of demand response, or if we're going to keep an energy-only market. Right now the decision hasn't been made, so we're still energy only.

But one of the things we did in response to that is we're raising the offer caps. And for 2011 they're $3,000, 2012 $4,500, they go up to $9,000 in 2015.

We do know that that will incent more demand response, at least passively. Again, we just hope to have some kind of demand response programs where we can capture -- we know what the price sensitively is where we're going to break off at those different points. And I'll talk about that in a minute, what we're going to do about that.

Just so you know how often we have these scarcity pricing intervals, when I looked at last years' data we were -- one of our problems is our energy is really too cheap. Our wholesale prices, in Texas a lot of it's natural gas and a lot of wind, too. And 97.7 percent of the time we're under $50 on our wholesale price for power, for a megawatt of power.

Going up to $100 it's 1.4 percent of the time. Up to $1,000 it's one-tenth of a percent. And up to the peak it's only four-hundredths of a percent that we're at anywhere close to the peak prices.

So, you know, one of our problems is that prices are so cheap we can't get generation built and we also can't get demand response because why would anybody want to go to all the trouble being really hot and uncomfortable on the one day a year where it's really hot out when the price is this cheap. So, anyway, we're working on that.

One of the things we -- we think we've got a lot of commercial participation and what we'd really like to see is the mass market for -- the DR for mass market residential customers to come into play. But because we have the retail choice, it's really hard for the aggregators to come into Texas.

Retail switching, people are switching every six months or a year. And, you know, an aggregator or someone, a service provider doesn't want to put in a $1,000 piece of equipment and then have it be useless six months later when they switch to another provider.

Also, our retail electric providers don't really have an incentive to, or the desire to try to -- well, they'd like to lock a customer for three years, but no customer wants to be locked up for three years so it's really not a selling point.

And then it's just the cost and infrastructure of putting in a device.

So, there's really three people that want to make money in a retail case, the DR provider or the person who's putting in the equipment wants something, usually a capacity payment. The residential customer wants a cost savings or a capacity payment. And a retail electric provider wants something for going through all that trouble.

So, that's really where our -- where we have the most ability to have DR and it's also the hardest place for us to get DR. You actually would have an easier -- an easier go at that in your current structures that you have today.

Some of the things we're working on. We're trying to encourage and make the rules better where loads can participate in a day-ahead market, where they could set a kind of a bid to buy, what they would buy up to. And if they're going to buy above that, it just wouldn't clear that amount and they would know that the state can curtail during that time.

And we're also, by next summer, hoping to have what we call loads in -- or loads in our five-minute dispatch, where they could actually -- we're trying to move the people that are passive responders into setting what their bid to buy is and then that way our market clearing engine will know that they're going to curtail during that time, instead of having price reversal type events.

And that's all I have for now. I look forward to the questions.

MR. ETO: Thank you, Joel.

Our last panelist is Michael Robinson. He's a Principal Adviser of Market Design at MISO. He provides expertise in the design and analysis of the markets to be operated by the MISO, including imbalanced energy, ancillary services, and the congestion management markets.

He assesses the potential effects of market rules and design features on market performance and he was primarily responsible for crafting the Midwest

Market Protocols Documents back in 2003, which was one of the bases for the energy market tariffs. Mike.

MR. ROBINSON: Great, thank you. Thank you for this opportunity to speak to you about how MISO incorporates demand response into our markets.

I’m going to give you four major points and then I’ll open it up for questions.

The first one, I’ll talk about our philosophy when we create these markets and how we accommodate demand response in those markets.

The second point will be we’ll talk about the different markets we conduct and the state of demand response in those particular markets.

The third element we’ll talk about is the role that MISO plays versus the states. We’re operating in 12 states and one Canadian province, and soon to be three or four more additional states at year’s end.

And then last we’ll talk about how we’re trying to facilitate increased participation of demand response in our markets.

So, first, market philosophy here. You know, our main function at MISO is reliable grid operation and we think by administering these markets we’re enhancing reliable grid operation.

And so when we -- when I started crafting these, we started crafting these market rules, we come in to try to create an open, wholesale market where there's voluntary participation on both the buy side and the sell side by market participants.

And so there was some talk this morning about treating demand response as a generator. We're not trying to give equal treatment to demand resources. We're trying to provide comparable treatment.

But the difference is that demand resources can either participate on the buy side or the sell side, and so they have a different advantage than generators do.

But our whole goal in mind here is to conduct these markets so that they're fair, efficiency, and nondiscriminatory.

So, if we send a price signal and the consumer values their consumption greater than a price, then they can consume. If not, then they can drop off.

On the supply -- That's the buy side.

On the supply side there may be a mill that wants to do some load drop, but it's got to send a shift, the plant, of workers home for the rest of the time period.

We accommodate that by allowing that demand response to specify its physical operating characteristics, like a minimum run time. So, to the extent we commit and dispatch that resource we would respect that and so that load would drop off for that particular period.

And so that's been our philosophy from the very beginning is to conduct competitive efficient markets to support reliable grid operation.

Having said that, we have no demand response programs in MISO, none.

Okay, I think Susan mentioned a little bit earlier here in the past history of some of the RTOs they've had programs. Programs come with lots of attributes that are not desirable in my opinion, like short transition, transitory nature of the programs is one.

And the second one is typically demand side programs come with side payments that somebody else has to be charged for.

And so when we've designed our markets we have no programs but we allow demand resources to participate fully in all of our markets.

So, we conduct five markets. We have an energy market in real time and we're co-optimizing our operating reserves with our energy market, both in day-ahead and real time.

So, an energy market, a regulation reserve market, a spin market, non-spin, and then we have a capacity market.

We also have demand response as being considered in our planning process on an equal basis, so demand resources may substitute for transmission or generation infrastructure build in our planning process, and then we have emergency procedures where we have some additional demand resources that can participate.

The operators are blind to what type of resource is providing the service. So, if a demand resource can provide the service, like for regulation telemetry requirements are required, AGC control is required, the ability to every four to six seconds is required, then demand resource can participate.

And so the operators do not look at the type of resource, that’s not in the algorithm, they just dispatch based on least cost managing congestion.

So, we have demand resources participating in energy.

In the regulation market we have roughly 75 megawatts of true demand resources participating. We’re a 100,000 megawatt system on energy, roughly. We procure roughly 400 megawatts an hour for regulation, just 400.

At any time, typically demand resources will clear for providing regulation roughly 40 megawatts out of that 400. This is a true demand resource. No behind-the-meter generator is supporting load increasing, load dropping.

And we've done performance analysis on this asset and they perform better than generators. This true demand response resource has performed better than generators who are providing regulation service.

Spinning market and non-spin, we procure roughly 800 megawatts for each one of those services every hour. In the beginning, when we conducted our ancillary service markets we put a 10 percent cap on how much demand resources could provide spin.

The reason we did that was the operators in our shop were concerned about the reliability of demand resources providing spinning reserve service. I'm sort of putting it nicely, concerned.

You know, these operators come from utilities and from local balancing authorities and they're used to, in a contingency, calling on a big generator to provide the contingency reserves.

And so when you're asking them to provide smaller demand resources to provide it, they were skeptical. We've relaxed that cap and now it's at 30 percent.

We have roughly 150 megawatts of demand resources providing spinning reserve today. They perform better than generators again, we've done the analysis.

In non-spin we're procuring about 800 megawatts. It varies. You know, there's not a whole lot of money in the non-spin market. The average prices are 10 cents per megawatt per hour. So, we don't have a lot of participation, it sometimes could be half, sometimes less than that.

On the capacity side, 100,000 megawatt system, 9,000 megawatts of demand response, roughly half is true demand response. The other half is supported by behind-the-meter generators.

And so we're quite happy with our participation. The key here, though, that we respect is the role of the states in terms of providing demand response versus the role that MISO and the FERC plays because, ultimately demand response occurs at the end-use customer level. And the rates, terms and conditions that those retail customers face are the purview of the state regulatory bodies and other retail regulatory authorities. We respect that.

And so, essentially we're not looking behind the curtain, what we're trying to do, I think Susan mentioned it, lots of outreach trying to -- we speak to the Organization of MISO States. We go out and do training, education, try to provide the value that these demand response assets can provide in our markets, where it can free up generation to provide electricity, but at the end of the day that's what we do, we just provide that training and that education.

I'll give you another different example, that when we first started these markets in 2005. We provide L&P, L stands for location, but also it's important that prices vary by time and location. And so we have prices for roughly 30,000 electrical busses that we create every hour.

Now, a particular vertically integrated utility and most of our load-serving entities in our footprint are vertically integrated utilities under regulated environments, we have some retail choice states, just a couple, but some participation, but a load-serving entity may, say, have 1,000 electrical busses. We have separate prices for each one.

They can, if they so choose, receive a locational marginal price at every one of those busses. So, they can reflect to their end-use customers, if they so choose and the state regulatory body chooses to do so, send the correct price signal to those customers based on what it cost to serve them at their withdrawal points.

Some of our entities have taken us up on that, so they broke out their load into smaller segments to better reflect the cost to serve at those different points, location and time. Others are still providing an average price across all of their withdrawal points.

But again, this is something where we have this in our tool chest. If the states and load-serving entities want to provide that signal, they can.

And so lastly how do we -- how do we get more participation? Well, the key, the real answer is market fundamentals and we're long. We've been long forever, since we started this, 20, 30, 40 percent long. And so, as I said, non-spin prices are 10 cents a megawatt per hour, spin prices are a dollar per megawatt per hour, regulation ten bucks, energy prices are cheap. Not a whole lot of incentive for demand response to participate in that sense.

We do see load-serving entities who are getting short, in terms of having supply, come in with more demand response. There's a lot of demand resources that are not participating in our market but are there at the utility's call, they can use them.

More of them are coming in. As they get short we expect the market fundamentals to change in the next couple of years with the mercury and air toxic standards coming out in 2014 and 2015, and other EPA regulations.

That’s the main one. We have accomplished quite a bit in terms of getting over the operator reluctance of having demand resources providing some of these ancillary services, so that’s been a significant step.

And we have a vigorous stakeholder process where the stakeholders can come and suggest barriers to participation, and we can address those.

In particular we had one. When we started the ancillary services markets we were requiring demand resources that provide spin and non-spin to have telemetry. There’s no reason for that so we got rid of it, and we have more participation for these assets in those markets. Telemetry is required for regulation and remains so.

More recently we’re offering multi-part bid blocks for demand resources to provide ancillary services because they have costs that can vary by how much they’re providing. We’re going to drop that in next year sometime, again, a way to sort of reduce the barriers to participation.

So, we’re continually looking for artificial barriers to participation. To the extent they are artificial, we try to relax them and get more participation. Thank you.

MR. ETO: Thank you very much, panel. So, thank you for the brevity of your remarks. I think we have ample time for a good discussion, so look forward to hearing from the Commissioners and the panel.

CHAIRPERSON WEISENMILLER: Joe, let me start off with a general question for people. One of the things which we were certainly struggling with, like in the capacity symposium, was what is the value of a centralized market, where you basically have demand response competing with refurbs of power plants or any number of options, as opposed to having sort of stand-alone or utility-specific markets?

MS. COVINO: Well, I'm not the economist here, Mike is, but the first thing that pops into my mind is that you meet the obligation, the total peak amount that you need to have at the lowest possible price, which is what markets do, do very well, so that the cost to the consumers is as low as it can be and still maintain the level of capacity that you need.

CHAIRPERSON WEISENMILLER: Yeah, I was trying to get a sense of is this one-tenth of a percent effect, which still in these markets is large, or is it 5 percent? If anyone has a sense of what the scale is, that would --

MR. ROBINSON: Yeah, it's more like 2 or 3 percent in terms of least-cost dispatch in terms of savings over a period of time.

MR. MICKEY: And all I'd add is that I think the -- like you said, the central market way is arguably the most efficient, but it's also the least controlled way to maybe get the DR. You can get it much easier if you do it the other way.

COMMISSIONER MC ALLISTER: Let's see, I've heard a theme where, you know, sort of decide to different degrees in your various presentations, and also this morning, sort of, you know, make it as simple as possible, you know, decide what the attributes of the product categories are. I guess I'm sort of intuiting that it should be a limited number of products and not, you know, a huge panoply of products.

But it brings up questions about what the best way to go about having that conversation is and defining the products actually would be. So, what is that -- you know, I appreciated your going through the markets that you run.

And I guess I'm kind of wondering how you ended up with the buckets or the products and the particular markets that you have, like what did that conversation look like to you?

We're starting in a different place in California and need to embark on that discussion and it would be kind of nice to have a little bit of specific, you know, ISO-specific or regionally-specific information about how that actually played out.

MR. ROBINSON: I mean I'll jump in to start. I mean it started with NERC requirements in terms of meeting CPS-1 and CPS-2, the standards, the DCS requirements.

And so the history of these utilities is providing this kind of, you know, regulation service, and spin, and non-spin service.

When we first started our energy markets we had roughly 26 local balancing authorities who were continuing to provide those ancillary services. We were just conducting energy markets a day ahead in real time.

Clearly, that was not efficient and there was lots of money being left on the table. So, once we became the central market administrator for these ancillary services, there have been significant savings that we've documented.

So, it starts with the NERC standards. And then what we're doing now is where California's looking at the need for ramp capacity, we're looking at the same issue and the issue is whether we should create a product and call it ramp product.

We're still involved in the stakeholder process to do that, but it certainly is on the table because we see a lot of significant amount of wind coming in from the western part of our footprint.

COMMISSIONER MC ALLISTER: That's really interesting. And that -- it sort of begs another question on, okay, how -- you know, you need the flexibility, you're not sure maybe exactly how many -- you know, what the dividing line between a ramping product is, in terms of numbers of time you call it, and a permanent load-shifting kind of product in this baseline question.

And I guess I'm also -- maybe as we go forward you could also sort of talk about that issue as -- you know, if it's relevant. If it's been relevant for you or if it is relevant for you now, and how you define your product categories. I don't know if I was clear there.

MR. ROBINSON: Yeah, in MISO we're -- I think Susan talked about price-responsive demand. We have some of that in place, too. But in the Midwest we don't have a lot of -- very few of the retail customers are on some sort of dynamic grid, very few. And so it's really not an issue.

To the extent more of them became sensitive to real-time pricing, we'd have to incorporate that into -- as Susan said, into our UDFs, our forecasts.

The issue in terms of the ramp product, we're doing a full-blown, you know, cost benefit analysis which involves can we meet this need with more regulation?

I mean right now, again, we're only procuring 400 megawatts in a 100,000 megawatt system. Could we procure more and use that for ramp? It could be fairly costly. And so we're looking at, you know, what's the best choice? First answering the question of do we actually need a ramp capacity product.

MS. COVINO: And these markets evolve over time. Pretty clearly, as we gain experience with demand response in these markets we learn things.

And our planning department was noticing that demand response, participating as capacity resource was growing as a percentage of peak over time. And they began to be concerned because our product only requires them to reduce ten times over the summer.

As they grow from 4, to 5, to 6, to 7, 8 percent of the peak logically they need to be able to reduce more frequently to be a bigger percentage of what we're relying on.

We got the curtailment service providers together and they said it’s just not going to work for us. We’ve got multi-year contracts in place that were expensive to put in place in the first place, and now we just can’t run out there and undo them on a dime. We’re going to have to work through this.

Ultimately, what happened is we’ve retained that original product but limited how much of it actually can make up the peak and developed two additional new products. One an annual product that looks like energy efficiency or generation, and another called extended load management, which is able to reduce more frequently, for more hours over the summertime.

But we also -- I found very useful to use what we’re calling advance technology pilots to get a sense of what’s being developed out there and what we might expect our grid operations, how they will change over time as new technologies come in. And we found that that’s had a very significant advantage for our stakeholders.

MR. MICKEY: From ERCOT’s perspective, I guess most of our demand side products started out as regulatory -- excuse me, reliability products. Some of them were even held over from the regulated days where we used to have customers that curtail, again, only in emergencies.

So, they started out, they would be really what the ERCOT ISO's reliability needs where and then whether they could meet it. And then over time we started looking at what they were capable of providing and that's why we changed some of those hours around and stuff to get more participation, and also more competitiveness to the offer prices.

So, we've had those reliability DR products for many years and that's all working pretty smooth.

The current thing that we're interested in is demand response for resource adequacy needs. Our reserve margins are declining every year and, you know, there's really only a couple of hours over a couple of months that we need more resource adequacy, and it makes more sense, at least economically, if you curtail a little bit of the load than to have new generation built that's sitting around all year long wanting to recover its fixed costs.

And then the last thing is, from an economic perspective, you know, you got supply and demand. You don't want your demand to be un-elastic. You want to be elastic. And so it makes a lot of sense to have a greater portion of the demand that is exposed to prices and can interrupt during those high price signals, instead of just sending that signal only to generators. Just economically it’s not the best way to do things.

MR. ETO: MaryBeth, did you want to comment, also?

MS. TIGHE: Yes, I could just -- can you hear me there?

MR. ETO: Yes.

MS. TIGHE: Yes, okay, I would just like to add to what Susan, Joel and Mike said that it started with the functions that were needed for the system, improvements were made over time and I think the -- one of the things that we at FERC have looked at over time are there particular barriers that require some policy changes. We’ve focused a lot on compensation for energy and for regulation, in particular, that in some places demand resources weren’t being paid for providing the services, or they were being paid differently from other resources that were providing this service.

So, we tried to regularize that by making a rule that would be, you know, applicable across the country for demand resources when they’re providing these particular functions.

COMMISSIONER MC ALLISTER: Thank you very much.

CPUC COMMISSIONER FLORIO: We’re a little short of time, so I'll be brief. With PJM I understand you have the three demand response buckets. Can you give us a little bit -- you said one was only ten times per year, but that was capped at a certain percentage. What was that percentage and how did you come up with it?

MS. COVINO: The planning department came up with it in terms of the relationship between the percentage peak, that we could have that kind of a resource that only has to interrupt ten times per summer for six consecutive hours. And how much -- what percentage of the peak that could be and we used that in the clearing mechanism.

We were surprised because the first year that this resource actually participated in the auction there was a price differential in what it got paid, and we didn't expect to see that, you know, for two or three years down the road. So, the market seems to be working as it should.

CPUC COMMISSIONER FLORIO: So, it was a lower price for that because there was more of it available?

MS. COVINO: Right.

CPUC COMMISSIONER FLORIO: And the other two were an annual product and --

MS. COVINO: Extended. Extended load management.

CPUC COMMISSIONER FLORIO: Okay, and what are the parameters around that?

MS. COVINO: The extended is for the summertime, only. I believe there's a month added on and it also needs to perform during the month of May. It's something that the curtailment service providers who aggregate direct load control can manage.

Instead of six consecutive hours, it's responsible for coming down for ten if we need it.

CPUC COMMISSIONER FLORIO: And is that limited also in how much can be in the market?

MS. COVINO: Yes. The planners do the same kind of an analysis around that and limit how much of it clears to ensure that we have -- we've actually made our adequacy targets.

CPUC COMMISSIONER FLORIO: Okay, and then the other was an annual product?

MS. COVINO: Yes, that's a product that's able to come down or reduce load all the year round, and it has specific requirements during the summertime that vary. They're different from the parameters that govern its obligations during the wintertime, when our peaks are in the early morning and in the early evening during the wintertime.

CPUC COMMISSIONER FLORIO: Okay, but that would eliminate things like HVAC that are primarily summer-driven loads?

MS. COVINO: Yeah, I mean fundamentally this recognizes what we have always recognized about generators. Different kinds of generators have different attributes and they participate in the marketplace, in our markets differently, depending on those attributes.

The same thing applies to demand response.

CPUC COMMISSIONER FLORIO: Thank you.

COMMISSIONER MC ALLISTER: I wanted to ask Mike just a question. You, in a couple of your markets, I think it was regulation and it may be spin, you said that your demand response participants were actually performing better than generators. And could you just detail a little bit what you mean by that and how you measured that?

MR. ROBINSON: Yeah, I mean essentially we measured it -- first, it's a limited sample. So, we have lots of generators providing these services, we have just a few market participants providing demand response, so there's probably a little bit of self-selection here.

COMMISSIONER MC ALLISTER: Uh-hum.

MR. ROBINSON: But how did we do it? We looked our dispatch signals to these assets and we measured how they responded, sort of tracked it over a period of a couple of years and compared that to demand resources to generators. And when you do the comparison, again, the demand resources are much more able to follow dispatch.

COMMISSIONER MC ALLISTER: So they delivered --

MR. ROBINSON: They delivered, yes.

COMMISSIONER MC ALLISTER: -- what they promised to deliver more reliably and --

MR. ROBINSON: Exactly.

COMMISSIONER MC ALLISTER: Okay, interesting.

And then for all four of you I had just a quick question. I guess what's your sense of how much automation is actually being used in these various marketplaces? Like what's the application technology that you're seeing? And, you know, maybe that's a broader question of what the dispatch actually looks like, but I'm interested kind of in the application of automation.

MR. MICKEY: Well, I was going to say I think most of the automation that I know of is done at the aggregator and the service provider level, and that's not what we're doing at the ISO. We're coming up with market clearing pricing and sending out a signal, and it's getting to those DR providers that are either aggregating those things together or it's going through a single site where they've got the Honeywell, or whatever the other type technology that is actually controlling lights, and turning on and off motors, and those kinds of things.

COMMISSIONER MC ALLISTER: So you're not necessarily -- you're not necessarily equipped with the visibility down into what's really going on, you're just seeing the product being bid in and seeing it appear when you call it?

MR. MICKEY: That's correct.

COMMISSIONER MC ALLISTER: Okay.

MR. ROBINSON: yeah, I would say the same. We're sending signals to the market participant and, as Joel said, the market participant maybe had more automation in terms of how they're sending their signals to the end-use customers, but we're not seeing that directly.

COMMISSIONER MC ALLISTER: Okay, thanks.

MS. COVINO: The only thing that I would add is that that newest option for load reduction capability that I described when I was speaking, called price responsive demand, requires automation for the load reduction that's actually participating as price responsive demand.

And that is so we can have visibility. And when a load-serving entity says, you know, your load forecast says I'm going to be serving 400 megawatts at a price of $200 it's wrong, it's only going to be $150, so adjust your load forecast we're dispatching the energy market based on that information and we have to be assured that those resources are responding to price in the manner in which they've told us they are.

So, the automation will be a feature, if you will, of price responsive demand.

COMMISSIONER MC ALLISTER: Great, thank you.

MS. TIGHE: And this is MaryBeth. Just to add from sort of a view looking across the country we -- FERC requires each of the RTOs to have protocols for measuring and verifying performance.

And we find, we see that the level of sophistication of the measurement of verification is largely a function of the product, itself. So, it's possible for energy to measure performance using metered data that is submitted, you know, maybe every two weeks or even a month.

Whereas I think several of the speakers there mentioned that for regulation service, which is a very quick, it needs to be a very accurate, very rapid response you must have telemetry to be able to make sure that you're getting the up and down movement that the system needs.

So, we see sort of a variety of measurement and verification protocols, really more as a function of product than of the RTO, itself. There's starting to be a lot more standardization among the RTOs in terms of how they measure and verify their different products.

MR. MICKEY: I guess to add to that, so when I answered your question I was speaking from a wholesale market clearing perspective. That's a good point.

There's a whole issue about measurement verification. If we're going to pay for something, we want to measure it and verify for it.

If we're not making a capacity payment and a customer's just not wanting to be exposed to that price, then we don't need to necessarily have measurement verification under certain conditions.

But that, M&V is a very important thing you'll have to deal with about if you're going to do it, how are you going to do it, how erroneous -- or how difficult it's going to be to do. Excuse me, not erroneous.

But we do have to automate that part of it. If we are doing the M&V to a thousand or a million residential customers, we got to have a way of doing that baselining and bringing all those meters in, if you will, and seeing if they actually performed.

COMMISSIONER MC ALLISTER: Yeah, I'll just say, we never do onerous or erroneous regulation here in California.

MR. MICKEY: Yeah, of course not.

COMMISSIONER MC ALLISTER: Everyone knows that, right? So, anyway, I think we should move on. I think we're out of time now. Right, Suzanne? Yeah, great, so thank you very much to the panelists.

MR. ETO: Let me thank the panelists for their time and experience. I hope it's informative to the discussions we're having in California. Thank you very much.

(Applause)

MS. KOROSEC: All right, can we have our next panel come up to the table, please?

Our moderator is Mary Ann Piette.

MS. PIETTE: I think we'll go ahead and get started if folks are ready to go into the next session. I wanted to introduce you to this session on Enabling Technologies to Support -- I'll start over.

My name is Mary Ann Piette from the Lawrence Berkeley National Lab and I'm the Director of the Demand Response Research Center. It's a pleasure to be here today. I'm looking forward to discussing with you some of the work that's going on related to enabling technologies to support demand response.

And we all have slides in this session. This is a technology session. We will try to go through them quickly. And I have six slides, myself, to introduce the topic, so let me go right into that.

Go ahead to the next slide. I want to first give you a little bit of history of some of the work we've been doing at Lawrence Berkeley National Lab. We've been funded primarily by the California Energy Commission and we're working on something called OpenADR, Open Automated Demand Response.

And this technology was first tested in the field ten years ago, when we did five buildings using an XML signal to automate demand response.

The goal at that time was to reduce the probability of future brown outs or black outs by developing a low-cost technology that would enable price response.

So, the concept was if we had default dynamic pricing in California then we would have customers automatically responding to hot summer day congestion pricing events and loads would be automatically enabled to respond to some sort of dynamic price.

That technology is here today but the market is not. And we'll talk about the state of the technology, OpenADR related and other things as well.

The technology is something called an Open API, an Open Application Programming Interface. And the first OpenADR spec was published in 2009. And Barry's going to talk with you a little bit about ADR 2.0, which is out this year and starting to hit the market.

But OpenADR 1.0 is fully commercialized in California and the utilities offer it and it is being used.

What happens is the utilities actually have servers that send continuous signals minute by minute, all year round to loads, and the loads are preprogrammed. Most of the loads do not get retrofitted, they're using the existing control systems, but sometimes we retrofit.

And the graphic there shows that OpenADR is what we call an application programming interface. It's a data model where we turn the prices into signals and we communicate them over the internet.

Notice in the graphic there the signals go out to the buildings and it's not real-time KW. But for the fast ancillary services demonstrations and pilots we have real-time KW.

So the price to install automation depends on what features you're deploying in the market. Go ahead to the next slide.

We've been looking at the concept of using demand response to look like a grid scale battery. So, how can we aggregate fast loads and deploy them?

And when we started this work we didn't really know how fast the internet could be and how fast this XML programming system might be.

But over the years we've gotten a lot of experience in installing the automation in the buildings, in getting signals from the ISO, working with the electric utilities and then actually sending signals to loads, and then looking how quickly those loads can respond.

So, we've been able to do that with the 4-second telemetry that the ISO requires on some of the fast ancillary services, both non-spin and regulation technology products.

So, we've been able to demonstrate -- now, it's still expensive to do that. And we can talk about that's one of the challenges, how much does it actually cost to install the telemetry. And that's one of the challenges, how much cost per KW or some sort of metrics to get these systems installed.

I think one of the themes we want to think about in the future is automate once, use many times. So it may be that you install it for a day-ahead, slow DR, but you actually find that load can be for fast DR, so it can actually participate in multiple programs.

And the comment earlier about who owns the customer is a very compelling one and that's one of our challenges. The loads can do it, but our markets are one of our challenges. It's how to engage the customer in these multiple value streams. And I do think there's a big opportunity to do that.

And I also think it's important to remember the more predictable the load, the more predictable the DR. So, we were talking about M&V a minute ago and we know some loads, like Target and Wal-Mart from this morning, are very predictable and they're great DR loads.

So we know a little about M&V and M&V is related to predictability.

Go ahead to the next slide. There's been a lot of work going on over the last few years to try to characterize what we know about how flexible different end-use loads are and we're looking at all sectors, homes, buildings, wastewater. Agricultural pumping in California is a very good load.

And we've been doing research on what -- how often can you call that load? Is it accessible? Does it have a rebound factor? And these things are starting to come out in reports.

So, we begin to know what the low-hanging fruit might be, the customers that actually will provide this resource and can provide the resource.

Go ahead to the next slide. This is my -- I think I got a couple more. This is a slide about our work with an ARPA-E Project to try to look at how low can the telemetry platform be.

So here, we're going to talk today about what's required today for the ISO products and then how can we actually install fast telemetry systems to get signals to loads and to get the real-time KW. And in some of these loads we have real-time feedback, so if the load doesn't hit the target it's going to ramp a control strategy up or down to try to get a particular KW.

So there is a lot of work going on, on how to create the telemetry platforms to enable these loads and to get this technology out in the field.

The next slide. Here, this project is about our Los Angeles Air Force Base, where it's a two-way vehicle to grid. There will be a fleet of 40 vehicles and we're looking at how to use the vehicles that the Air Force wants in L.A., they need a lot of cars, and they're going to actually look at selling these batteries back into the grid.

So, again, we have a lot of paradigms for new loads to participate and we're -- there's a lot of projects underway to try to look at that technology infrastructure.

So, this is an OpenADR system with regulation and vehicle-to-grid two-way batteries.

The next slide. So, this is my last slide. And in summary I just want to say that we are looking the communications technology, automation and information technology, which California is a leader in, and we want to look at fast demand response and expanding the set of demand side options for loads.

It's very important to look at rate designs so we can get different kinds of price signals to loads.

And I'll make one comment about the bills. Customers care about reducing their bills and bills are very complicated these days. So, while we've been rolling out this concept of default dynamic pricing, our automation is able to do these things but customers are still pretty confused given the wide variety of things on the market today.

I'm going to introduce my three speakers all at once and just give you an idea of what to expect in the next three presentations.

Barry Haaser is here with us from the OpenADR Alliance. And the OpenADR Alliance has been working to organize the testing and deployment of OpenADR 2.0, which is out now. And that has formal conformance and compliance methods.

Barry has a lot of experience with these organizations that do these alliances and technology. He's been involved in the Energy Information Systems Alliance, the LonMark International and USNAP Alliance, and he's President of the Lakeview Group.

So, he was selected when we were looking to move OpenADR from the lab into the market, we brought Barry on to help us form the Alliance, which now has over a hundred members.

So, we're happy to have him today and he's going to be talking about what the OpenADR Alliance does.

Next we'll have John Dilliott from UC San Diego. And UC San Diego is one of the largest DR customers for San Diego Gas and Electric. And he's the Energy and Utilities Manager at UCSD.

John, I think you're on the phone there, right?

MR. DILLIOTT: Yes, I am.

MS. PIETTE: Okay, so he'll be speaking about his work on the campus and you'll get a look into the way they organize their demand response.

And he’s from the US Merchant Marine Academy, involved in their central plant, their CoGen systems and their overall demand response technology.

And last I have Jacqueline DeRosa from the Customized Energy Solutions. And she is here in Folsom, California, working on technology to help enable advanced markets for ancillary services. And she’s the Director of Regulatory Affairs with Customized Energy Solutions.

So, let me turn it over to Barry.

MR. HAASER: Thank you, Mary Ann.

All right, next slide, please.

As Mary Ann mentioned, the OpenADR Alliance was formed really to bring the OpenADR 2.0 profile specification to market. OpenADR 1.0 was an initiative kicked over a decade ago and it was evident to the participants supporting that Open API that they really needed more structure to get a certification and compliance program operational.

So, over the last three years we’ve been able to do that. We’ve ramped the organization. We now have over 100 members in the organization worldwide. And we’re really focused on bringing OpenADR 2.0 not only to market, but propelling it and getting industry adoption, not only here in California, but throughout the U.S., Asia and Europe.

And we do that through collaboration and education, building industry awareness, et cetera.

We're not a standards organization. We use existing industry standards. I'll talk about that a little bit in a minute.

And, really, it's an issue of bringing together common stakeholders that have an interest in sharing and deploying OpenADR technology.

The next slide, please. So, if we look at the goals that we set out to accomplish about three years ago, again, we're not a standards organization, we do collaborate with other standards organizations. It's very important for us to use the accepted industry standards. Some organizations we've worked with are SGIP, when it was part of NIST, Oasis, and we follow also proven internet standards for how the information is sent.

We've built a testing and compliance program. We've tested and certified several products for compliance with the standard.

We're in the process, now, of finalizing what's called the OpenADR 2.0b profile specification. That will be the most widely adopted portion of OpenADR. And we’re anticipating testing and certifying the first compliant products within the next couple of weeks.

So having completed the first two goals, we’re really now focused on the next part of the equation which is building education and awareness, and really trying to propagate adoption of this important industry standard.

So, you’ll start to see the OpenADR Alliance becoming a lot more visible in terms of public advocacy and industry outreach and education.

And that outreach is not only targeted at ISOs, RTOs and utilities. But also a key part of this equation is making sure the building owners, and operators, and system integrators understand how to take these control attributes and deploy them in buildings so that buildings not only are more efficient, energy efficient, but also have the ability to benefit from these new programs **and** technologies.

And that will help in terms of industry adoption and market acceptance.

I will mention that we just learned that OpenADR has been accepted as the national standard in Japan. It looks like Korea is pretty close behind. And we’re seeing a lot of growing interest in OpenADR also, now, in Europe.

The next slide, please. So, I mentioned standards previously. There has been a tremendous amount of input that's gone into this OpenADR standard. So, we've obtained input from all the key stakeholders in industry, as is evident from this slide that all went into the mixing bowl and we published what's called OpenADR 2.0, which is a profile specification. Basically, it's an XML scheme, an internet standard.

We have now taken that foundation of OpenADR 2.0 and proposed to IEC so that it can become an international standard as well, and this will be very important for international acceptance of the standard, again in Japan, the rest of Asia, and in Europe.

The next slide, please. So, if we look at OpenADR 2.0, again this is a matter of broadcasting price and event information from a server to a client. We can go through attritional aggregator models or directly from CAISO directly to a customer.

And then once it gets to that customer, and that customer can be residential, commercial, industrial, agricultural, OpenADR doesn't really care how it gets there. We're seeing the development of a number of OpenADR interfaces. There are now some OpenADR thermostats so you can have native OpenADR communication from a server directly to a thermostat, so you could participate in an AC cycling program.

Mary Ann talked about what's happening with the EV charging project. There are a number of projects underway there.

Once it gets into the facility though, say for example in a commercial building, it will then talk whatever that native protocol is or standard in that building.

So, what we've built here is a very fast, effective and secure pipe from the energy provider all the way to the customer. And we are now building a whole ecosystem of compliant products so you can effect OpenADR, again, in a thermostat, a residential gateway, or even a building automation system, or a lighting control system.

So, there are about 80 companies that are in the process of building OpenADR directly into their product. So, essentially, it's coming for free.

The next slide, please. So, if we look at where this is heading, OpenADR 2.0 is an industry standard. It's widely recognized and acknowledged as the standard for automated demand response.

Again, there are over 100 companies. Our 2.0 profile specification is open and available for anyone to download from the OpenADR.org website.

We're averaging now about ten downloads a day of this profile specification. So, interest in the specification is very large and I would say probably 50 percent of all the downloads now are coming from outside the U.S.

Because the interface is standardized, we now have a framework, unlike 1.0 where the interfaces were tied directly to the server. Now, it's possible to have interoperable products or interchangeable products on the customer side of things.

So, if a customer decides to change from one program to another or one service provider to another, they don't have to replace the hardware for that system. That system will migrate from program to program. Even if the customer moves from one location to another, it will still work.

Title 24 has a reference in it that every building over 10,000 square feet requires an auto DR interface. This means that starting next year we will see a significant bump in the number of DR participants. Again, OpenADR is being built directly into building automation systems, lighting control systems so it will essentially be there. So, Title 24 will help build the market along a little bit faster, as will the changes in the LEAD program. There's a reference now so that you can get LEAD credits for having an auto DR interface.

Most of the California IOUs, and actually many of the utilities in California have either active OpenADR projects or pilot projects underway so we're going to get a lot of cumulative data starting next year.

And again, worldwide we'll see a significant uptake.

So, I know it's a bit of an eye chart, but that forecast from Pike Research shows the market for OpenADR at about 80,000 buildings.

Given what I'm seeing in Japan and here, with Title 24, we'll surpass that in the next couple of years. So, this chart is already out of date.

And that concludes my presentation, thank you.

COMMISSIONER MC ALLISTER: Can I just ask a quick question? Mary Ann, I just want to -- so, on the slide, let's see, the previous slide, yeah, that one.

So, could you talk a little bit about the data analytics in the bottom left-hand part of that slide? What sort of -- who's using those analytics and sort of what services are enabled by an OpenADR protocol?

MR. HAASER: Yeah, so we provide reporting mechanisms back as a standard part of the 2.0.b profile specification. And what we're finding is with many of the systems that are being developed today there's a focus on metadata. And the applications that are being built, these OpenADR servers are providing location-based solutions for DR, either based on load, or region, or what have you.

So, it's not just an issue of having a server that sends out a signal, the engines that are being built are much more sophisticated and are dealing with large amounts of data. Not only in terms of what is out in that -- the number of participants in the program, but also on the data that's coming back in terms of verifying participation in the program.

COMMISSIONER MC ALLISTER: So, I guess just the point that I think I heard is that this platform systemizes data in such a way to make it much more useful according to the customer needs, or whatever their needs might emerge.

MR. HAASER: Yeah, that's kind of beyond the scope of what we're doing in OpenADR, but we're delivering the mechanism for the data.

COMMISSIONER MC ALLISTER: Okay, great. Thanks.

MS. PIETTE: Thanks Barry.

Our next speaker is John Dilliott, who's the Energy Manager at UC San Diego.

Go ahead, John.

MR. DILLIOTT: All right, well thank you very much. And thanks again for the invitation. I'm glad to participate. And I know a couple of the Commissioners. Chair Weisenmiller has been to campus, so greetings again to him.

And, of course, Andrew, we miss you down here in San Diego, where he was -- we're always asking him for money through the California Center For Sustainable Energy. So, we do what we can.

But for those who haven't been to our campus, and I think we're in a good spot to highlight some of these technologies, because we're fairly -- I'd call us kind of a medium-sized campus, but we do peak out at about 42 megawatts. We're about, you know, a campus of about 45,000 people each day, 11 million square feet. And we're all behind one meter so we sort of fit into that micro grid category because we have 1,200 acres, and we have wires that go from one utility interface on one side of the campus, on one side is the freeway, all the way down to the Scripps Institution of Oceanography.

So, we've got a lot of buildings, a lot of big buildings and we use automation all the way and really participate as much as we can in demand response.

Saying that, with a cogeneration plant, we have a 2.8 megawatt fuel cell, we have solar PV, so we've got a little bit of everything and I'll kind of go through how we participate.

Go to the next slide, please. And so we can participate pretty well. So, even with the 42 megawatt peak, we're only importing 12 megawatts at a time because we self-generate about 30 of it.

But with an 11 -- a dispatch from SDG&E over the phone, or at this time going through maybe an aggregator at the time, we're able to shed that load pretty quick. It ends up being in this one case, you know, 40 percent of our load. And this is all of our metering as well, so we can keep track pretty well of what's going on.

The next slide. And really what we do -- this kind of was more maybe towards the first presentations, you know, what we do. So, we do have a centralized utility plant where we do some stuff behind the scenes.

Oh, if you can go back one, I think it's there. And then really what I think we do for this particular case here is this automated control of our thermostats. Because really it's thermostats that really kind of control everything in a building.

They not only control -- especially in a variable air volume building they'll control the fan energy so we can get that box to close, that all those boxes are being controlled by the thermostat. But it also controls the main air handler which has the chill water valve. And so once we start clamping down on the chill water valve and we say it's pumping energy from the central plant, then we can also get the chillers to back down at the plant and maybe take off some electric chillers.

And then also, at the same time we will do as much static pressure resets on the air side as we can and on the water sides as well.

We are a heavy research campus, so we really can't mess around with static pressures and laboratory buildings that fume hoods, but we've been pretty good with the design. So, we have non-critical zones that are not on the same air handler, or not on the same static pressure run as the labs, so we're okay on that.

Then, of course, do voluntary conservation as much as we can with the 45,000 people.

The next slide. So, really I wanted to show you the amount of, what do I want to say, points, or these are all controllers. These NAEs are the new sort of Johnson controls. It's called a -- it's sort of their network control engine.

I don't know why, Mary Ann, that's -- yeah, that's a good one. So on all of those buildings, and we have combined, really, energy efficiency and demand response programming on all of these because almost all of these buildings over the last couple of years we've hit with either energy efficiency, retrofit projects, might have been a variable air volume, or we've gone back and we have recommissioned those buildings through our energy efficiency program.

And any time we go in there -- really, it started off with using the control system just to turn stuff off on the weekends and nights. There was a lot of energy to be saved there. And really, setting it to, we called it, a standby or unoccupied time within the thermostat, itself. And so that is actually a lot of work.

And so when you talk about was it the cost of programming that from getting, like I say, a Johnson Controls technician out there to go into every space, and into every building, and move these set points around.

So for us, we take it just from a 70 to 74, which we call unoccupied, and we'll take that to a 68/78 and either a standby or unoccupied mode. And in a standby mode there's still minimum ventilation. In an unoccupied mode we take the unoccupied ventilation rate to zero, but it still could be override if the temperature in the space got over 78 degrees.

But saying that, we program that -- if we can go to the next page -- all of those points then we have programmed up into a single button.

So, getting back sort of to auto DR, I'm a big proponent of anything you can do manually you surely can do automatically.

So, if we get a demand response all we have is an operator that goes in there and clicks the lab load shed, so you see about five buttons there. All of those buttons are already programmed, so we're very compatible to get that OpenADR signal and have that automatically release those points. So, we're right on the verge of doing that we hope to show how we do it, and how that works with either a JACE box or we would like to see, really, coming straight from the ADR signal straight to our controllers, skipping all the middlemen in between.

And I think you can go to the next one and even to the next one as well.

And then we do some central plan activity. As you can see here, we have some large chillers. A chiller that is running with a 5,000 volt, you know, 3,000 horsepower motor. Those kind of things we do kind of keep control at the central plant. We have operators there 24/7, especially during the hot time.

So, there's some stuff that we will or will not ultimately release to a third party to shut off because you cycle -- if for some reason that signal got corrupted or that signal went on and off, if you start cycling a big motor like that then you can have really damage on the equipment, so we looked a little bit at that.

And then you also show a picture of a thermal energy storage tank in there. You really can’t use that for demand response even though you think that it’s a big battery, but you’re cycling that every day. I’m going to get into some economics of it, and if it’s not a part of your baseline then it doesn’t do you any good.

But one thing we sort of do is we play sort of an energy arbitrage against the summer peak time rates. And I’ll do something, what I call super discharge the tank, meaning that if I’m running electric chillers during that time I can take that electric chiller off and I can discharge the tank. But the tank will be fully discharged before the SDG&E peak time ends, which is at 6:00 in SDG&E range. So, if I get a call that’s from 2:00 to 5:00 and I deplete the tank by 5:00, and I have to bring on extra chilling resources between 5:00 and 6:00 and I’ll hit -- potentially hit an on-peak SDG&E summer on-peak rate.

So, I would include that in the rate structure that you wouldn't be penalized for using your thermal storage tank, otherwise you're going to keep electric chilling on the line, and an electric chiller included with the cooling power pumps is probably over 1 megawatt for each chiller. And I can take four of those off during a -- if it's the third day of a heat wave.

Can you go to the next slide? I'll sort of wrap it up. And then from the demand -- from the economic side, so participating in demand response really is just two things to think about in our stand point.

One is the economics of it, of course. And then the second is the reliability.

So, we've had wild fires down here in 2003 and 2007, and we also had a regional blackout in 2011. On both of those cases economics are thrown out of the table and it's the reliability of the campus that's important and we will -- to have these resources and the ability to drop so much load and to actually use our campus generation to island ourselves from a utility grid, we're devoting a lot of effort into that right now.

But from a demand response side and economics of it, having been in the program since about 2003, I tell you right now the capacity payments are the definitely preferred method.

Energy payments don't add up too much. We're bidding in maybe 4 megawatts right now on a program that pays $500 a megawatt hour, so it's basically $8,000 an hour. I know it sounds like a lot, but it doesn't really add up to it in the grand scheme of things.

And there's also baseline calculation, what they currently do, which takes the previous ten non -- or ten days that aren't a weekend or a holiday and they say that's what you need to get down to.

And for us that could be -- if you call it on the first day of a hot day, I can shed 7 megawatts and still not get to 4 megawatts because all I've done is gotten back to my baseline, and then I'll get penalized for it. And a penalty is a non-starter in my book.

California can't use backup diesel generators. I didn't hear that a lot from the PJM, but I do believe that they are allowed to use those kind of resources in the East Coast. You'll never be able to do that in California.

So, you can go to the next slide and I'll wrap it up.

This is an example of how -- and, actually, we were under a service aggregator that really dropped us because we put in our contract that we couldn't have penalties. And this is just on a 3.5 megawatt bid we started out at almost 12 megawatts, dropped it almost to 4, and we had about a 7 megawatt drop and I still didn't make my number and we got penalized for that.

And so we did not even participate in demand response in 2010 and 2011. We had to wait until another program came along called the Demand Bidding Program through -- it's really through SDG&E and it helped us start participating.

If you read that tariff, as it exists today, it says there's no penalties and they're taking just an absolute drop of your load when you get called.

So, I think those are a couple of things that would make us participate even more.

And that's sort of it for me.

MS. PIETTE: Thank you, John.

We'll get back to questions after the last presentation, which is Jacqueline DeRosa from Customized Energy Solutions.

MS. DE ROSA: Hi. I'm Jackie DeRosa, Customized Energy Solutions. And thank you for the opportunity to describe our technology that has been in commercial operation for several years now, and its applicability to California's demand response arena.

First, please let me describe my company so that it will make a little bit more sense as to why I'm here and where our technology fits into our business model.

Customized Energy Solutions is a comprehensive energy consulting and services company. We're based in Philadelphia, Pennsylvania.

Can you go to the next slide, please? Our company was started in 1998, so we've been around for a while. We have offices throughout the United States, Canada and India.

My company's services range from economic forecasting, regulatory and engineering analysis to progressive data acquisition, telemetry and scheduling services for a wide array of wholesale and retail clients.

Our goal at Customized is to simplify and encourage participation in the competitive energy markets. We're the one in the middle. We're the one that's trying to make it simple from the customer to the RTO or ISO.

A key part of our business involves a 24-hour market operations center where we schedule and operate over 3,000 megawatts of generation, load, demand response, renewables and electric storage.

So we're operating right now the flywheels, and the batteries in the PJM and New York markets. We also have dispatchable wind and conventional generation, as well.

We're a smaller company and we represent many smaller facilities, such as those who participate in the demand response programs in PJM.

So, when we started this participation in DR, in the eastern RTO, we realized we had to develop a secure and lower cost alternative to the traditional communication and control infrastructure that's used for conventional larger facilities.

And again, that's why I'm here today to describe technology alternatives that we currently utilize, that we develop and we utilize in the eastern RTOs.

So, several -- let's go to the next slide please.

I know this looks complicated, but for these guys this is nothing. Several years back we developed a rapidly deployable, encrypted network technology called Secure Net RT.

And we use this in the demand response program in PJM. We utilize a very similar approach to what's described here for the storage resources in this markets and generation, as well.

So this diagram, it visually describes how our approach works for demand response. So you can see that on the right side of the picture we're showing our customer sites. At the bottom we show the interconnection to the California ISO, or the RTO, whichever. I have California ISO there, but it could be any RTO.

And at the top I show our Customized Energy Solutions control room.

So, in this instance we would have -- instead of having a direct line between the resource to the ISO, as currently is required in California, we instead consolidate multiple participants' real-time data in our EMS system back in Philadelphia, and we then provide that data as a single data stream directly to the ISO or RTOs via an ICCP link.

So, this is a way to have a secure and rapid real-time communication between the multiple locations, so the customer sites, the Customized Energy Solutions control room and the RTO by using an encrypted tunnel, using standard network protocols.

We utilize this approach for participation in the energy and ancillary services markets in the other RTOs.

Next slide -- here we see a picture of the secure net RT box that's in use. You can see that this little box, I put a light bulb right in front of it when I took the picture, but that box is about 8 inches by 8 inches. And, you know, not to sound like I'm a sales rep, because I certainly am not, I'm the Director of Regulatory Affairs, and this little encryption tunnel box that we have is just a small piece of our business. But, basically, I have plugged these things in, that's how easy it is.

I mean you can ship them out and plug them in. It's like a plug and play.

And it encompasses the encryption and the controller or the RTU. And in terms of encryption we use the strongest commercially encryption technology available, which is the AES 256 bit.

Our systems also use a bidirectional authentication. So, for example, we authenticate the end user and the end user authenticates that it's customized.

We're also our own certificate management authority.

So, if we could go to the next slide? Here's just a -- basically, so we have that box at the site. We also have the HMI with the customer.

So, we basically take that communication and we're communicating it at our control room. This is the interface at our control room in Philadelphia that's the in-between between the RTO and the customer.

So, here's the interface at our operations center in Philly. And in this example we have two participants, to clients that are participating in the sync reserves market. This is our ending, 17. And you'll see on the left that the -- or I'm sorry, in the middle where the green circles are, that's showing the status of communications and it's indicating that we have good connectivity.

And if we were to have a spin event in that interval, then we would -- the control state would change to on for the clients that were in the given hour, and the spin events would toggle to red depending on the region that the spin event was called for.

Once that happens then the client's site automatically, everything is automatic, receives a signal to reduce their load or start their engines. So, we remotely do that, as well, with toggle switch in our system.

So, this could be done for, you know, a building management system or a furnace control system, all types of demand response.

Again, it's an automated, simplified approach.

Okay, next slide, please?

I've tried to outline here some of the advantages of this type of technology. The main point

I'd like to make is that it's simple and that we've doing this for years and it's in commercial operation.

The hardware is a lower-cost option than the existing remote intelligent gateways currently required in California.

And if the internet were used, such as in other markets, it could also replace the need for the ongoing AT&T ECN connection costs.

As I mentioned, the box can be installed quickly, within an hour, and we can activate it remotely. We use the secure net RT for participation in energy and ancillary services markets, including regulation. It's almost instantaneous, the signal.

By aggregating the information as well into our system, in Philadelphia, we simplify the workload for the RTO control room operators. They no longer have to communicate with a multitude of smaller customers that don't really do or understand the details of the ISO or RTO world.

We are the in between people that -- we're like the universal translators.

The next slide, please? So, I know we've heard a lot about the challenges regarding implementation of demand response in California and the message has been consistent, you know, over the past -- today and over the past that the technology is there, that the technology really isn't the barrier.

But I do have to point out that there are some barriers for implementing the technology. Even if all the jurisdictional issues were resolved and the program design matters were finalized, we couldn't still do this in California right now.

And the reason is because the current rules for telemetry and metering were developed, you know, before all this stuff was invented.

Fortunately, there is a great group at the California ISO who is addressing this and they have a proactive approach to evaluate a lot of these issues so that, you know, that they can be resolved and that they will no longer be the barrier that prohibits participation.

But I did list a few of the barriers that are currently in the rules. They are being addressed. But right now, as I mentioned, you're not allowed to concentrate the data into a centralized location.

The internet's not allowed. You need to have the AT&T ECN.

ICCP protocol is not allowed to aggregators or data concentrators.

And right now there's resource ownership rules and location limitations for concentrating data.

The next page, please? I do want to say, though, that I think those issues could linger if they weren't -- if there isn't a little bit of extra pressure, and participation and comments in the stakeholder process at the ISO.

But overall, it's a great place, California. Thank you for the opportunity. It doesn't get any better.

MS. PIETTE: Okay, that's the comments on the technology we have today, so let me open it up to your questions.

MS. LEE: Thank you. I'm Audrey Lee from the PUC. I'm an advisor to President Peevey.

I had a question for Mary Ann Piette. You said that the telemetry costs are $10,000 to $25,000 today and the target is for $200.

What are some of the technology advancements that need -- or are they market issues with, you know, wider deployment?

And then that's related to Jacqueline's recommendations in terms of, you know, how to reduce costs. I'm wondering how much could those -- what difference could those recommendations make, like if you went from ECN to internet what kind of reduction would that be?

MS. PIETTE: Yeah, the comments Jackie just made, she gave you a pretty good list there of some of the specific issues. And I know Heather's very familiar with these. There is a working group underway. And so this is an active area of research and engagement.

Essentially using the internet, the internet can do some of the fast telemetry that's needed for the ancillary services.

You have to have a certified rig, which Jackie was just talking about, to participate in the programs today. So, we're looking at can you provide those features that exist in the rig in newer platforms.

So, a couple hundred bucks per KW might be a feasible price point that we think we can do.

In the Demand Response Research Center we had our first ancillary services demonstration, it was 70 K per site, $70,000 per site for the telemetry. Then we got it down to $7,000 per site. A lot of evolution of the technology over the last few years and we hope, you know, it will be hundreds of dollars in the future. Go ahead.

MS. LEE: Can you just put it in context? So, in my home I have a Smart Meter that measures my usage.

MS. PIETTE: Yeah.

MS. LEE: You know, what added features does the rig have beyond --

MS. PIETTE: Yes.

MS. LEE: And, you know, I have a gateway that communicates with the internet.

MS. PIETTE: So, we've been looking at -- we think we can get 10-second data off of your Smart Meter, but that 10-second data need to be collected in a home gateway and then served up to the internet.

OpenADR uses both what's called a push or a pull client. When we use OpenADR for fast ancillary services we push the signal quickly over a dedicated internet signal. So we don't use, necessarily, the public internet, but it is still the internet.

So that's an example is at home, if you're with, you know, Comcast or some other provider, that we want to use a more dedicated, secure internet technology.

Do you want to make some comments?

MS. DE ROSA: I would just add that in the other markets where we do use the internet, we do use wireless, you know, we use encrypted public network communication so that would reduce the ECN costs which are -- I think our -- we're paying like probably $500 a month. And I think there's a different range of services for the ECN through AT&T, depending on what your bandwidth is, so it could be higher, it might even be a little bit lower.

In terms of the actual like rig, so right now you have to have a rig at the site directly connected to the ISO. In California you could have multiple rigs in a sub-lap, so in a small geographical area.

And I think the reason cited by the ISO for that, primarily is that's just how things developed initially, and also because of security reasons.

We haven't really viewed that -- we haven't had that security issue voiced in the other -- in PJM. We have a redundant system in our Indiana office and we have -- you know, everything is encrypted. So, I don't believe if you have aggregated rigs that everything's going to be encrypted in that little sub-lap between the rigs.

So, I don't know that -- our position would be that our system is probably even more secure.

But in terms of like the cost of what that little box is, you know, our -- as we described our company business, we're the middle man, we're the in between so we're not just providing -- we're not selling those boxes on the shelf at Wal-Mart. But everything that's in that box is off the shelf. We build that based on what's available at the store. So, that box is under $1,000.

MS. SANDERS: Okay, I just want to offer a couple of things for the record. This is Heather Sanders from the ISO.

We do not require you to use the Energy Communication Network for every product. If you're providing regulation or spinning reserve, yes, you have to use the ECN currently, in the rules.

But for proxy demand resource you can use the internet. It just has to be encrypted using SSL.

The reason for the ECN, if you want to use ICCP, is because ICCP isn't a secure protocol, so use the Energy Communications Network to add that layer of security. So, there's reasons for these things.

As far as the rest of it, we're working on it. You know, the rules were established a while ago and we are working on all of this.

Olivine, Spence Gerber is in the back there, they have implemented a software solution for the rig so you don't have to have a physical box.

So there are alternatives and we are progressing. We do recognize, though, that we need to evolve this and we're working on it in a stakeholder effort this year.

I just wanted to provide a few clarifications because we do allow the internet, DMP-3 protocol with SSL encryption for PDR, non-spin and energy.

MS. LEE: Yeah, and I'd just like to add that our office is working on a rulemaking, and working very closely with the CAISO so, hopefully, we can resolve all these issues, but it takes time.

MS. DE ROSA: I would add, too, that we're fortunate to have a pilot project in with the -- what do you call them, not a pilot or a demonstration. What's it called? A pilot, you know, where we've implemented our technology and are evaluating the data transfer.

MS. SANDERS: Yeah, I was going to say don't we have an ACCP link with you right now, just testing all the things you were complaining about? I mean we do, right?

MS. DE ROSA: Wait, I have to caveat, I said you guys were really proactive. In the BPMs and tariff there's about 900 references to telemetry and metering. These guys are great. They found them all and listed them out.

COMMISSIONER PETERMAN: It's often nice to ask people to do things they're already doing so you get credit for it afterwards.

COMMISSIONER MC ALLISTER: Really, we're getting to the good stuff and, unfortunately, Commissioner

Florio has to leave us.

But, so Mary Ann, I wanted to kind of -- the reason I really wanted to have an enabling technologies panel was to really talk more broadly about what's possible, give an update on OpenADR, you know, get a little bit of -- give us a step towards what's coming down the road.

And maybe -- this is unscripted, so you can say no if you want to. I didn't give you the heads up. I was going to ask a broader question.

So, you know, storage is another set of technologies that is an enabling technology for demand response. I'm wondering, you know, you guys are doing so much over there at the DRC I wonder sort of what are the promising areas that you're looking at, in addition to the ones that we've heard about here today?

MS. PIETTE: Yeah, one of the questions I was discussing with some of the panelists this morning is the idea of how a load expresses itself to the ISO or to the utility that it's available. And there's a huge interest at DOE, from Roland Risser, on that topic.

So, and it may be on different time scales it expresses its availability.

What's probably the most exciting thing in California is we have the hot summer DR technology.

It's not moving quickly, but we really want to have multi-purpose programs, I think. And that's a challenge with this issue about who owns the customer.

But a load, if a load has storage it can do different things on different time scales. You may want to charge the storage, you may want to dispatch the storage, you may want to predict the storage.

So, the mass of the building is storage, the ponds at the wastewater facility is storage. The frozen products at a refrigerated warehouse is storage.

So, we've talked about some of those, but we haven't talked about how somebody knows those exist.

The historical performance data, that's one way they exist. It's just say what have you done before? Are you reliable? Are you predictable? If I call you, will you do what you did last time?

And the aggregators have a lot of experience with that. The more aggregation you have, the more predictability you have, as well. So, that's one thing.

And then the really fast demand response, we need to know what is that load doing right now. And that's harder to know, but we think it's very real.

Danfoss is asking about putting OpenADR right in the VFD.

So, we're beginning to have new ideas about how these loads can make themselves available.

Now, who are they making themselves available to? To the ISO, to the aggregators, the utility, you know, and how does the customer know is this -- can you call me continuously?

The second one is how storage and demand response can work together. And we think the concept of what we've called battery-firmed demand response, where a small battery and the DR work together makes the load shape even more predictable and you can bank on those.

So, at San Diego, you saw that John has a variety of resources that he can call upon. And I think it's extremely important to acknowledge that he had economic motivations, as well as emergency motivations. So when there was an emergency, he could do it even more.

It's really good to know when an event like Sandy is coming. So, emergency and resiliencies, those are important. And those are like insurance for the future.

So, the more we characterize to the customer what we want out of your loads and how can you express yourself to the grid, it may be your historical data, or it may be something more about reaching deeper into the loads and expressing them. So, those are a couple of ideas.

COMMISSIONER MC ALLISTER: Very interesting, thank you very much.

Anybody else? All right, well, I'm helping you catch up a little bit, we're only 40 minutes down, now.

Thank you very much for the panel, I appreciate it very much.

(Applause)

MS. KOROSEC: So our next speaker -- actually, two of our next speakers are up on the dais and we've just decided that they can present from up there and I'll run the slides for them.

So, our first speaker is Heather Sanders from the CAISO.

MS. SANDERS: Thank you. End of the day. The first slide, please. Thank you.

We just published a road map last week that seeks to focus our efforts on increasing demand response and energy efficiency directly and expressly to reduce or offset the need for new generation or transmission.

Before I get into that, I want to thank a lot of people for helping in the development of that road map.

I have two folks from the ISO here, Lorenzo Christophe and John Gooden. Lorenzo and John contributed significantly to the road map you see now, as well as several others at the ISO, Neil Miller, Judy Sanders, Delphine, Greg Cook, et cetera, and it couldn't have been done without them.

Also, all of you; I learned a lot from you and I appreciate you coming to our workshop at the ISO and sharing your experiences. And then all my follow-up questions about, well, you've said you want this, but how do you exactly see that working?

So, we're trying. We're trying to learn about demand response and we're trying to learn about energy efficiency.

And at the same time we're also trying to help you understand better what we're facing as grid operators, and that's what I'm going to focus on now.

This is the infamous duck. I hope you have all seen it. This is an old duck. There will be a new duck. It will look the same.

We are getting data from the utilities on actual renewable procurement so that we have the mix of resources that their procuring to construct "the duck".

So, we need to look at how we design our demand response and energy efficiency and, really, everything that we put in this mix that modifies the load shape so that we have the resources when we need them, where we need them, at the magnitude we need them.

So, let's look at the duck a little bit. So, this is a load shape that we expect to see going in the future as mostly we increase solar PV. So you see the middle of the day drooping down lower and lower because we have all that additional generation from solar that's offsetting the load at that time. That's creating a deeper load shape.

You also see the peak increasing. When you look at these curves day to day you see the peak moving over time. It's 4:00, it's 5:00, it's 6:00, it's 8:00, the next day it's at 4:00 and the magnitude is shifting significantly by thousands of megawatts depending on the sun, and the wind, too.

So, what we need to do is really look at the load shape and design our programs with, you know, what are we really trying to do?

I wanted to say something here about operating reserve. People may not know, but the only time we can deploy operating reserve is in a contingency event. So we have energy, and energy is meant to balance the grid second to second, supply/demand balance.

That energy is usually thought of system wide. It helps us manage around the ISO to maintain the frequency, as well as our area control air, which is effectively, you know, how much we have scheduled in is coming in, how much is scheduled out is scheduled out. So, energy, second-to-second balancing, system wide resource isn't as dependent where it is because you're managing over the whole area.

Regulation is the 4-second that is managing in between the short time frames to make sure again, we're second-to-second balancing, so those two work together.

Now, operating reserves, we have spinning reserve and non-spinning reserve. They're both required within 10 minutes online. One is synchronized spinning and one is not synchronized, but it's available to come up within 10 minutes.

Now, those can only be dispatched in a contingency event. So, I've lost a transmission line, I've lost a generator, something has happened so you dispatch your reserves.

We have to recover within 30 minutes, according to WECC standards, and prepare for the next event.

So, that really points us to local resources. When you have an event, transmission planners need to make sure that the system can recover. Can we ride through that first one? Got to make sure you ride through the first one and you're repositioned to handle a second one within 30 minutes.

So, that drives a lot of our requirements for resources in our market. How long they need to be available, when they need to be available and how long they need to sustain that availability.

On Wednesday next week the ISO's having a stakeholder effort on the must-offer obligation for resource adequacy.

So, in the absence of a capacity market run by the ISO, we rely on the PUC to do procurement. And this works.

So for generation they procure in the long-term procurement plan to make sure we have enough resources where they're needed.

Annually, in the resource adequacy proceeding they do showings to make sure that, yep, here we go, we have the resources, we have them where we need them.

So that we can, in the spot market, dispatch those and make sure they're in the right place.

So, transmission planning goes through and does analysis of all those local areas to make sure there's enough resources in the right places.

Back to the load shape, the peak is occurring, still, you know, later into the evening with solar. We're going to have to manage that peak.

So those programs that are there for insurance when we have high peaks are still important. We'll still need those. We need them, you know, at a certain level. We won't call them a lot, but that's what they're there for, they're insurance for peak.

We also need the capability to bring up that lower belly of the duck when we have over generation.

So, let me tell you why this occurs. You see that really steep afternoon ramp up, you know, you're going from the sun is full boat and then the sun goes down, and then you've got to replace that.

So what happens and why we're so concerned about this is in order for you to have the ramping capability, in order for you to be able to go from 11,000 to 23,000, 12,000 megawatts, you have to have generation online or a resource online that can do that.

Now, we have a log of old dog plants in this State. They're being retired through once-through cooling or they're being repowered, but they require to be on, turned on, running at their minimum operating level so they can meet that ramp.

So guess what happens? We've got all the sun going, we had to turn all these other units on, so we've gotten up to a certain level so we can manage that ramp.

We work on this. So, in those times, you know, if we have more resources that have minimum operating times or minimum operating levels that are lower, you know, they can ramp up faster, they have more starts and stops we're better off. Demand response resources have this capability.

So that's the duck. I wanted to just really hit on this again and talk a little more about why we're asking for what we're asking for.

So the road map has laid out four paths of activities. What we heard loud and clear in the workshop was that you can't just focus on the supply side ISO. You've got to focus on the load side, too.

We hadn't contemplated it initially because we don't have much to do with the load side. We don't design rates and we don't send signals directly to customers.

But as we thought about it we're like, well, we have a part of this because we're the ones that manage to that load shape.

So, if there are programs put in place that help more favorably modify that, that's good for the ISO. You know, our input on that is we need to think about the time, the time value of energy, and we need to talk about the ability for demand to increase in certain times, as well as curtail. We've talked mostly today about curtailment.

The resource efficiency path is just about resources, making sure you have what you need, where you need, when you need it.

One of the key activities that we've been talking with the PUC about and I think we're very well aligned on is classifying our demand response programs into those that are really load modifying programs, such as pricing programs, and those that are really resources like the base-interruptible program, or the demand bidding program, or capacity bidding programs.

Those that are resources are dispatchable, we can signal them. They can change their consumption in a matter of time, whatever that is, and then they can maintain for a certain amount of time.

We want to explicitly get those recognized and then define, as the ISO, as we do for generators, then what do those resources have to offer into the market? How do they reflect their operational parameters? How do they show their capability to the market?

We have seeked to define operational parameters in our market to reflect to that.

Now, we have a little lingo problem because we're like minimum run time. We're like, okay, now is that how long you sustain or is that, you know -- and then number of calls, you know, number of starts. We call it number of starts, that would be an event.

So we need to equate our language a little better so that we really understand that we've modeled all of these in here.

Operations; that path is a lot of the tactical stuff that needs to be done. It's enabling policies that we have, getting those implemented, as well as addressing metering and telemetry, and addressing other technical and automation areas.

Finally monitoring, this is your M&B, evaluation measurements and monitoring.

In this path what we are really focused on is starting out with an intent. What are we trying to do? We're trying to increase demand response and energy efficiency that offsets the need for generation and transmission.

You know, we've been invested in demand response and we've measured it to its forecast, but I don't know that we've gone back and really said did this do what we needed it to do?

In thinking of it that way, it might make sense to combine some of the demand response and energy efficiency offerings that we put out.

You know, the ability to put in energy efficiency measures that can also respond to signals, or to prices could be very powerful.

One of the things that I also recognized as we go through is we don’t necessarily understand what we’re trying to tell each other.

I spent a little bit of time talking about flexible capacity and we included in the road map, on page 12, a little call-out box to help people understand what do we mean about flexible capacity.

Because we can’t use our operating reserves, our spinning reserves and non-spinning reserves to respond to a drop in wind, or clouds coming over the sun, we need another ability to be able to do that.

And we’re implementing a flexible ramping product I believe next year, that will seek to procure resources, along with energy, that say, oh, I need you to hold back so you’re here for ramping, or I need you to provide energy. So, that should help.

We currently employ a ramping constraint right now because we have needs where the wind will drop off 800, 600 megawatts, you know, over an hour and we need to be able to replace that, and make sure we have that capability to replace that.

We talked about the importance of monitoring.

The other thing I wanted to bring out is the difference between an ISO market model and a market product. And this is really confusing.

So, participating load is a model, it’s not a product. The products in the market are energy, spinning reserve, non-spinning reserve and regulation.

The model is how you reflect that resource into the market. What are its capabilities? You know, how does it get settled?

So, proxy demand resource, for example, is a model that settles on a baseline. It allows the separation between a load-serving entity and a demand response provider.

And once the CPUC gets Rule 24 done, which we’re progressing very well on, demand response providers will be able to bring that into the market, the ISO market, provided that the rest of it’s worked out in terms of it makes financial sense, et cetera.

Other market models for demand response; we are going to implement next year the reliability demand response resource model. That is so we can link the base interruptible programs, and other emergency programs that the utilities have procured into our market.

You know, our highest priority right now is to use what we have, gain the operator’s experience in demand response, get their confidence up and get it into the market.

Edison has told me that they could bring 1,100 megawatts into the market next summer, 2014 through -- if we get Rule 24 done and we get the reliability demand response resource in. And we're going to do our part to get that done.

Our second priority is the flexibility. We have a high need for flexibility. And I need you guys to hang with us through this.

The flexibility requirements for demand response are going to seem very, very, very onerous. And they are because we don't know when the wind's going to drop off, and we don't actually know too far in advance when the sun's going to come through.

One of the things in the resource -- what's it called, flexible resource adequacy capacity must-offer obligation it -- I'm not going to say the summary of the acronym because it's not nice. You guys know what it is.

One of the things in there is, because we're starting out on this, we started out with three distinct needs. We have a need for maximum continuous ramp, 18 hours. You know, you start and energy just goes up without interruption all day.

We need to bring those resources on to meet that ramp, that's one.

The second one is regulation. That's the interest -- our intra-second changes that we need to match.

And the third one's load following; this is a much shorter time frame, it's intra-hour. And this is the sweeter spot for demand response. But because we're starting out with needing flexibility, we agreed with the PUC we're going to start with combining all of those three, simplifying, so to speak, the requirements to have a three-hour ramping with a 17-hour capability.

And I've already heard their response. So, yeah, I think it was very demanding. So, I need you guys to hang with us for a while because we need to get back to the procurement of what we need. We need to get back to the three individual things that really affect the load shape.

It's for the peak, it's for the less deep and it's for the less steep. And the flexibility is that less steep part.

So, we need to work through this and we need to understand what demand response can do and how it can contribute.

You know, I was very encouraged by what I saw Ron put together, where we stacked all those resources up there. You know, I've been talking with our folks internally because we've made an assumption, aggregators, utilities and others out there can assemble all of these programs together to provide and follow our signals.

I didn't know if that was true. I haven't gone out and tried to recruit any demand response end-use customers recently, so I didn't know if that was a reasonable assumption or not.

But now I've seen it, so I guess now it must be. And you can all correct me later.

Okay. You know, I put this on here yesterday, the ISO, PUC and CEC must collaborate. Actually, we are committed to collaborating. We've met several times. We are working together to expand this into a cross-agency road map.

And this table, which is on the last page of the road map, is here because of our CEO. He came to me and he goes, I read the road map, I like it, but what do we have to do versus the PUC? He goes, I couldn't quite follow all those small drawings of the -- you know, the timelines.

I'm like, have I got a table for you. What it shows is really -- it's all of us. It's not just us, up here. It's all of you, too. And we're really trying to understand what it takes to make it happen and, you know, set the policies and adjust the rules so we can make it work.

The challenge at the end of the day is we have to make sure we stay reliable. And we need to procure things that will ensure we make it reliable.

The more we get it into the market, the more we get the operators comfortable, the more we can make this happen. And I heard that with the other ISOs and as they advanced their experience.

One last thing I had to say. You know, I always have to phone a friend during these things to check stuff. So, I heard the gentleman from Ercot say that there was no need for telemetry on spinning reserve, and I knew there was going to be some backlash.

And so, because of that, I e-mailed our operators and I said, so what's up with this?

Apparently, the message has not been downloaded from the server. Let me go back to this one. WECC Balancing Standard 002WR1C, page 2, "Knowledge of operator reserve. Operating reserves shall be calculated such that the amount available which can be fully activated in the next ten minutes will be known at all times."

Operator comment, "The only practical way to know the operator reserve at all times, as required, and more specifically the spinning reserve portion thereof is to have some level of telemetry.”

This is not a requirement in the other reliability regions. This is a WECC requirement. And the message that has not yet been downloaded from the server is my next question to him, saying, are we working on this?

So, I appreciate this. The last one -- I’m taking comments again. I want to know how well we did on the road map, what else we need to do. You know, just anything else you can offer.

And again, we’re going to work very cooperatively with the CEC and the CPUC to line up our priorities and our activities so we’re getting what we need to get. So, thank you very much, I appreciate it.

COMMISSIONER MC ALLISTER: Thanks very much, Heather.

And it was a good cue to me to remind people and actually to say for the first time today, actually which I should have said early on was that this workshop is part of the IEPR process. And our goal for this activity is essentially to have a chapter in the IEPR that is focused on demand response. And so it is one of the top level sort of importance topics that we’re looking at in the IEPR.

And the idea really is to build on the good work that the ISO has done to get the road map going and sort of bring a complementary view to it and end up with an action plan of some sort for DR in the IEPR document, itself.

And so to the extent that that can add value and build on what the ISO and the CPUC are already doing, to catalogue some of that and then propose some next steps, some targeted pilot programs, things like that where we can functionally help flesh out the next phases of demand response. And sort of encourage learning from those and then feed back into the marketplace to help things move forward, that's what we're going to do in the IEPR.

So, that's the reason we're having this workshop here today and the reason that your ongoing comment and participation is really critical.

So with that, apologies for the collugey segue, but I think we can move on to the -- is the PUC next or let's see here. We'll go in order, yes, so Audrey Lee and Bruce Kaneshiro from the PUC.

MR. KANESHIRO: Good afternoon Commissioner, thank you for the opportunity to participate in your workshop here.

So, we're going to do a joint presentation and

I'll take the first half of this, and then I'll turn it over to Audrey.

So, I'll be going over what we have today in terms of DR through the utility portfolios. And before we go further, I'm Bruce Kaneshiro. I'm the Supervisor for the Demand Response Team at the PUC. I've been doing demand response since 2002.

Actually, I'm one of those individuals I think David referred to in his opening remarks as going on a long journey. It seems like a never ending journey with him. So thanks, David for that intro.

So, we can go to the next slide. So, I'll cover that first part, where we are in terms of some accomplishments, where the programs are and then the challenges today from the PUC's perspective. And then I'll turn it over to Audrey to do what we foresee as some new goals and a new framework for DR, and a bit about our own DR road map, you might say, in terms of some specific activities to try and advance our vision forward.

The next slide. So, I won't spend a lot of time with this. I think mostly everyone here knows about most of these accomplishments. I think David even covered a few of these.

So, we have Smart Meters out there. They've been approved. That was a long process here at the Commission in terms of approving the utility business cases and then now they're deployed.

We have protocols that measure the load impact. Prior to 2008 each utility did it somewhat differently, so now we have a standardized set of rules as to how you measure DR, what are the megawatts for a particular program.

And then two years later we have a cost-effectiveness protocol that was approved by the Commission. It will help us determine whether the program is actually cost-effective for ratepayers who fund these programs.

Also in 2010 the Commission issued a decision that capped emergency DR programs. This was in response to CAISO's concern that the utilities were a little too top heavy with that type of program. So, the cap is -- by 2012 it will be 3 percent of system peak demand and then it ratchets down to 2 percent by 2014. So, we're slowly moving those programs away from -- or the utilities away from the emergency DR and into price responsive DR.

We've had the aggregators engaged at the Commission, as well. So, in 2007 the Commission approved a set of DR contracts between the aggregators and the utilities that went for about 5 years. And then just recently, in January of this year, we've approved another set of contracts for Edison and PG&E. Those are going for two years, so 2014, '13 and '14.

With respect to rates there's been a lot of work here. I won't belabor it too much, but the main takeaway there is that default CPP started for the larger nonresidential customers in the utility territories. That started around 2010.

And then, recently, there's been a transition for smaller business customers to be at least placed on mandatory TOU rates, with default CPP coming a few years later.

And then the last point there, our most recent policy decision by the Commission is the Rule 24 decision that came out in November of last year.

That resolved large -- most of the large policy issues with respect to the bidding in of bundled customers into CAISO wholesale energy markets. There are some remaining items that we still need to finalize before that rule is done, but we anticipate that should be done before the end of this year.

The next slide. So, just briefly, the utility programs today, they are basically approved on a three-year funding cycle. So, the current cycle is for 2014 to 2014.

The utilities, again, they are the central operators of most DR programs. Of course, as I mentioned, there are DR aggregator contracts, but the utilities run most of them. And the programs are available to pretty much every sector in the State, ag, industrial, commercial, res, institutional customers.

They offer different incentive structures and they set different expectations for the participants, but they all target peak load reduction today, and they all are use-limited resources. So there are time and event limits for each of these programs.

The price-responsive programs, those are as noted up there, they’re triggered either by CAISO prices or some other proxy for price. They’re typically triggered the day before the load drop is needed.

And then you have emergency or reliability programs. Those are triggered usually within 30 minutes of when the load drop is needed. Some can provide load drop even faster than that.

And then you’ve got some new programs -- or not new programs, you would say, I guess, evolving programs that can do both. So, AC cycling is one example, which was an emergency program for decades. That is now a price-responsive program or has a price-responsive trigger added to it. So it operates in either scenario, emergency or price responsive.

The Commission is also authorized funding for various DR support activities and I've listed them there. Auto DR, for example there's a rebate program for customers that are interested in that to help offset the cost of the technology.

There's emerging technologies studies and pilots, special projects. We set aside money for evaluation, marketing, the Flex Alert Program. And then something we're trying to do more of, and that's integrate the DR with energy efficiency offerings so that customers can receive the benefit of both types of efforts there at once.

The next slide. So, this slide, just to give everyone a sense of where we are in terms of megawatts, so going back to 2008 I'm trying to show here where we are in terms of total DR by the utility portfolio. And those gray bars you see horizontally going across represent the 5 percent target.

So, in 2003 the Commission set as a target that the utility price-responsive programs be equivalent to 5 percent of system peak demand. And that was set in 2003 to be achieved by 2007.

So as you can see from the slide, we're still a ways away from reaching that because price responsive is the blue shaded part of the bar. So we're -- today, in 2013, we're still about 1,300 megawatts short of that 5 percent goal.

We just stacked the red or the emergency DR on top of that just to give everyone a sense of how much total DR the utilities control today.

I think that's the main take away from that. If there's any questions, I'd be happy to answer sort of why there's some fluctuations going back and forth there.

The next slide. So, we talk about challenges for DR. I think a lot of the earlier panels really brought forth what are the challenges. Many of the presentations made are things that we've heard at the Commission, in many of the proceedings. Really, I guess what you'd say is we have a tug-of-war between what's expected of DR. When you look at it as a supply side resource we want it reliable, we want it flexible, we want it fast.

And on the other side you have the demand side, where is it sustainable to have a program with those type of requirements. And the more you place on the demand side resources that are providing it, can they actually provide that.

So, I've heard a lot today from, for example, the customer panelists, aggregator panelists, things such as, you know, penalties. Should we have penalties? Penalties are non -- I think one panelist said a game or a show-stopper, right.

But, yet, in my discussions I think with some of my colleagues at the CAISO, well, without a penalty how do we know the customer will actually show up? Do we just take it on faith that the DR megawatts will be provided?

So, the Commission is constantly trying to balance these different needs for DR. Is it a supply side resource? How much can we expect of the participants, who are all volunteering for this, to be participating on DR programs, and as well as the aggregators who aggregate on behalf of them.

I think we can move to the next slide. So, to get more specific, just a couple of things to highlight, so May of this year the Commission staff produced a report, we called it the "Lessons Learned Report." It was an examination of the Southern California Utility Company Demand Response Programs as they performed in 2012. So, that was issued for comment on May 1.

And one of the take-aways that came out of that report is just this issue of reliability. What we found in looking at these programs, in terms of comparing what was produced on an expose basis versus what was expected by the utilities on a daily forecast basis is that we saw a huge degree of variability.

Some programs produced a lot more. In some cases those same programs produced a lot less than what was forecast. And then you've got other programs that consistently under performed.

So you have questions that were raised immediately as to, well, again how reliable is DR? What can we expect from them coming from a CAISO perspective, as well as the Commission's expectations of this program that ratepayers are paying for them?

Usefulness, so you know, we talked about earlier the megawatt problem. You know, how many megawatts do we have? We're not really hitting our goal. But I think as Heather showed in her slides, we've got a different horizon about to unfold for us. So, are the DR programs really useful today in that context?

And I don't think -- I think the answer is, no, they're not. They're currently designed, as I said earlier, to be peak load reduction programs. We don't have them designed, yet, at least in terms of being more flexible, in terms of ramping up and down. And they're definitely not fast enough, I think, in the way that I think Heather was describing that they have to be.

And I think we've talked a lot about point three there, the integration with the CAISO market. Yes, the DR programs are not yet bid into the market, they're definitely not, obviously not dispatched by the CAISO.

And so how do we get there? How do we integrate them over there? Rule 24, I think everyone knows, is one of the keys to that. Again, we hope to get that finalized over the course of the remainder of this year.

But until that happens, yeah, it's not very visible to the CAISO.

The next slide. I'm not going to spend a lot of time on this. I think we've heard a lot about the customer challenges. DR is not a generator. We've heard that many times at the Commission. What can we expect, what's reasonable to expect of this resource in terms of what customers can do and what they can't do. They have different needs and abilities.

One important thing to point out, that third bullet under number one, some changes, the DR programs have changed quite a bit in the last year. We now require locational dispatchability. Some programs have had to increase their hours of availability in order to become more cost effective. So, participants that have been on those programs may not be prepared for an increased amount of events or number of hours they have to perform when called upon.

There's issues of, again as we said, penalties. There's issues of testing. So, how do we know the DR program is going to be there, again, in terms of its megawatt capacity? We should do some more tests to make sure that it will show up.

So these are changes that are occurring the last couple of years. Again, adjustments made by the customer or the aggregators to respond to that.

There are some regulatory challenges. You know, one issue that's come up many times is that the funding cycle, the three-year portfolio is too short for many participants in terms of the up-front investment they have to do to participate in DR.

So, how do we know or how does the customer know the program will exist after three years? They don't know. Or the program will exist but it has been changed quite a bit.

Is that enough, I guess, to give them certainty that they should make that investment?

Funding uncertainty, there's all kinds of, I guess, sub-issues to that. I think what we meant by that is just that maybe from an aggregator's perspective, you know, they engage in an RFP process with the utilities. Those that are successful advance on.

The utility then comes to the Commission to get approval of those contracts. The Commission is required to ensure that these contracts are cost effective.

So, again, another hurdle in terms of whether the aggregator will be successful in actually getting a contract with the utility that's out there.

And then in terms of customer participation, I think those are pretty self-explanatory. Especially for the residential customers access to HAN, that's fairly new. I think that just recently started this year. So, there's not a lot of knowledge out there that customers can access their data in real-time.

There's marketing, education, coordination issues, there's a possibility of a lot of confusing going on with EEDR, Flex Alert, and so on.

So, I think that summarizes where we are and I'm going to hand it off to Audrey to talk about where we think we can go.

MS. LEE: And I just wanted to thank the CEC for holding this workshop and for all you to participate in. We're finding it really helpful and informative.

As I said earlier, President Peevey is planning to open a new rulemaking this fall, in September. And so that will, I think, time nicely with what the CAISO is doing in their road map and then what the CEC is doing with their IEPR.

And so, what I'm going to present are just some initial ideas for this rulemaking. And, of course, there would be -- we would hope to get a lot of stakeholder involvement in this rulemaking as we further develop these ideas or change them.

So as Bruce said, you know, one of the challenges with current DR programs is it's a tug-of-war between supply side and demand side.

And so how can we balance this? And I think what we've come to is we want to just separate them, that there are certain DR programs that are appropriate for the demand side that are customer-focused programs or rates, and then there are other aspects that should be -- go for the supply side, that they be reliable resources that are integrated with the CAISO market.

And we're very pleased to see that in the CAISO road map there is this similar, different paths you called it, kind of the load reduction path and then the resource path. So, I think we want to follow that same sort of framework.

And for the resource side, the supply side, I think it would be more of a procurement style program that would be where the resource would be defined by the CAISO, like the standard capacity product demand response -- for demand response.

So that the PUC would set a procurement mechanism similar to how we do procurement for supply side resources or, as Commissioner Peterman is suggesting, for storage.

And this would be third parties could participate, but utilities could as well.

And then on the demand side we would envision things like dynamic rates, demand response support, marketing, the integrated demand side management, and this is, you know, participation by both utilities and third parties.

And kind of in the middle we're trying to think about how we would transition this. So, in 2015 it would probably be a bridge year. And then for 2016-17 thinking about a pathway going towards more supply side resources, still allowing for the fact that we need some demand side resources. But we really want to transition those demand side resources to our supply side so that they are a dependable resource that can be put into the CAISO market.

And then just a little bit more on the demand side, you know, there are other benefits that the PUC will want to consider, more soft benefits that justify that demand side, whether they be environmental benefits that can't be quantified.

I think the next slide. And in thinking about the DR goals, sort of the demand response goals and the framework, so as I said on the supply side we want reliable and flexible demand response that meets system planning and operational requirements.

And so we would have targets and rules that we would specify -- the PUC would specify, very similar, aligned with decisions in resource adequacy, long-term procurement or the transmission planning process that we have with the CAISO.

And to help us avoid replacing or building infrastructure that's not needed.

And I think an initial focus would be on the SONGS area, in the Southern California area to meet those needs.

And we'd want to enable and increase retail demand response direct participation in the CAISO, as I said before. And have a mechanism for demand response capacity payments.

On the demand side we want to really ensure sustainable customer participation and encourage enabling technologies to help transition those customers to supply side in demand response framework.

We want to create customer focus programs to capture those soft benefits I spoke about earlier, like energy efficiency, distributed generation, water.

And then, you know, continuing to work on transitioning residential customers to time differential rates. And that's going -- rate design is going on in another rulemaking, and so we don't have control of that.

In the demand response rulemaking we would open, but we do want to coordinate with that and make sure that we plan for that accordingly.

The next slide. So, kind of going forward, our timeline, so by fall hope to finalize Rule 24. Our Director of our Energy Division will be meeting with stakeholders to discuss how we can speed up and resolve some of the remaining issues.

As I said before, we want to open a rulemaking in September.

We have ongoing interagency coordination with the CAISO and the CEC to develop our strategic plans, to develop our short-term and long-term policy goals, our framework and our road map.

And then we want to look at, in this rulemaking, the demand response delivery model and how to do cost recovery. It's likely, I'm pretty sure we'll do a bridge funding year for 2016 and the rulemaking would go into effect in 2016 and 2017.

And then that rulemaking would guide future demand response program design.

And then just also want to say that with our -- the PUC's resource adequacy proceeding we would want -- we plan to coordinate with them, as well.

And so, the 2015 resource adequacy rulemaking will get started in September, at the same time that we open this rulemaking for demand response.

And that proposed -- there was initially a resource adequacy -- sorry, I'm looking at my notes because I don't cover resource adequacy as much.

But last May they did have a -- resource adequacy did come out with the interim flexible capacity framework to meet local capacity requirements for 2014.

And then, so for the new resource adequacy rulemaking that will open this fall, that proceeding will determine what the flexible capacity requirements will be for 2015 to 2017. And then the rules and mechanisms to accommodate those preferred resources, such as DR.

So, we will want to ensure that we coordinate very closely with the resource adequacy proceeding.

And, yeah, I think that's about it. Next slide, I think we have -- okay, no more slides. Just making sure, sometimes we put a thank you slide.

COMMISSIONER MC ALLISTER: Great, thanks very much.

MS. LEE: So, thanks.

COMMISSIONER MC ALLISTER: So, just I might actually ask you a couple of questions. Sorry to slow things down here, but just so we don't lose the thread.

So, I guess I like the changes. I mean, certainly, there's a lot to like and I think, you know, you all are moving in a good direction with respect to locational -- some of the modifications of demand response that you've been doing.

Let's see, I guess, you know, the -- I'm wondering sort of the model of the market that you're thinking of, and I don't know how much, how deeply you've thought sort of -- sort of how much into the details you've delved here.

But, for example, in some of the renewables procurements you sort of carved out a piece that, okay, the utility's going to own this in the -- and, you know, the market's going to supply that. And you sort of add up to a whole that you're going to get to.

Are you thinking about something like that for the demand response approach, as well, sort of giving some of the utilities and then sort of the RFP would be the bulk of it, or some part of it?

MS. LEE: Well, I think process wise I think we'll draw a lot from the renewables procurement. So, you know, the length.

So, I think a PUC decision would lay out, very specifically, what those contracts would look like and then ask the utilities to have a request for proposals for that procurement, and then bring contracts to the PUC whether through an advice letter or application process, and then we would approve those.

But I'm hoping that decision will specify very clear that those contracts are more standardized.

In terms of the amount, I think we'll be guided by the resource adequacy proceeding decision about how much -- how many megawatts of demand response that we would ask the utilities to procure for.

In terms of who can provide it, I think we're envisioning the third parties but, you know, whoever can provide it, you know, at the lowest price, for the lowest cost to meet the needs.

COMMISSIONER MC ALLISTER: And I guess I just want to point out, you know, Bruce you were talking about the need for flexibility and, you know, demand response will be expected to do certain things, may or may not be able to do those things.

I guess we also heard from the aggregators, I think a couple of them, that actually the substitute ability that they provide is actually a service that they kind of bring to the table.

And that flexibility is something that they believe is part of their -- kind of something they bring to the table that nobody else really does.

You know, I think it came up in the penalties discussion, right, sort of -- or at least in the expectations. You know, the ISO would pick up, somebody would pick up the phone and call the aggregator or utility and say, hey, we need XY&Z resources. That aggregator, you know, if one customer couldn't get it done, then they can substitute with another customer, and that's kind of up to them whether there's a penalty or not.

But I guess I'm wondering sort of how you see the current structure of programs providing a platform for that kind of flexibility or that involvement of the aggregator kind of model?

MR. KANESHIRO: With the current programs, so the utilities do have bilateral agreements with the aggregators and it basically works the way you just described.

So, the aggregator is contractually required to provide a certain level of DR megawatts per month and they're paid a capacity payment based on that amount.

And so how they balance the need -- I guess the limitations, as well as the abilities of their end-use customers is between them and their customers. So, they basically spread that risk around.

And so, yes, that flexibility that's provided by the aggregator does mitigate to some extent the concerns of the customers.

COMMISSIONER MC ALLISTER: Uh-hum.

MR. KANESHIRO: I think what I was pointing out, though, is that sometimes, well, depending on what the requirements that either the Commission or the CAISO might set for that, for the DR, as you continue to add on to that it becomes a little more challenging.

Like, for example, location of dispatchability, as I understand, is quite challenging for the aggregators because you're only asking for DR in a particular portion of the utility territory.

So, the spreading of the risk across all of their participants is actually not, as I understand it, not available in that scenario.

COMMISSIONER MC ALLISTER: Possible, yeah.

MR. KANESHIRO: So, those are some examples of how, you know, again, well-intended principles are being put forth in terms of what we need, but it does have an impact on the end-use resource.

COMMISSIONER MC ALLISTER: Well, do you think scale in any -- across the State, you know, presumably in all the important regions would actually, you know, likely provide that kind of flexibility, sort of that redundancy and that flexibility that the aggregators -- you know, if they had more -- in one particular pocket if they had more participation and more different types of loads, and those loads were mapped into the right places and the right products, presumably that would increase the flexibility that they have and then bring those products to the utility or the ISO.

MR. KANESHIRO: Yeah, presumably. Although I think there are different customer mixes in different areas. So, I think down in San Diego those are mostly commercial customers, not much industrial.

So, there are some limits just based on what's out there in terms of the customer stock, you might say, as far as a particular region.

But you're right, I think overall with more participation there's probably more likelihood of trying to spread that across a little bit better.

COMMISSIONER MC ALLISTER: Yeah, go ahead.

MS. SANDERS: So, currently flexibility is going to be a system wide resource, not a local resource. So, local resources are intended to address transmission constraints and transmission contingencies, so that's local resources.

This gets very confusing because there's system, local and flexible, so system and flexible are system wide.

Now, we do have a requirement to bid these type of resources in a locational way because we need to dispatch them that way.

But as far as meeting the requirement, flexible is considered system wide.

So, we are looking at, you know, that locational bidding as well, you know, to see what we can do in the areas of system and flexible resources versus the ones that are procured for local requirements.

So, it gets confusing when it depends on what need you're trying to satisfy.

COMMISSIONER MC ALLISTER: So, I guess I'll just make the pitch, you know, I think it's really -- this is really important, right, because the ISO needs -- at some level needs to have comfort and communicate, you know, transparently what that comfort looks like to them, what's going to give the ISO some perception of low risk, like this will work and we're not worried about it, and our operators are comfortable, and we're going to dispatch it even though we don't have visibility all the way down to the customer level.

And then there's got to be all the different links in the chain to get down to that customer and get that customer motivated to actually do something.

So, you know, these operational characteristics like, you know, understanding them in great detail is super important.

And I had a couple of other questions, but I'm going to allow us to leave the ISO realm and go over to SMUD. Last, but definitely not least, in our presentations.

But thanks for bearing with me there.

So Harlan.

MR. COOMES: Harlan Coomes from SMUD. I'm a principal engineer and I've been working with demand response for many, many years.

And in some respects what we've been talking about today is a bit of "Back to the Future" for me because we've experimented along with PG&E, and others back in 2000 and 2001 with demand bidding, and all kinds of interesting things using the internet.

But, you know, prior to that SMUD has many years of experience, starting with the CEC back in 1977 with doing air conditioning load management and switches.

The reason why I bring that up is that -- next slide, please -- is that I'm calling this the new DR. And there's some key attributes here.

And automated, ease of use we've talked about a lot of this all day.

But visibility of location, availability of resources, all of this sounding familiar? Somehow I seemed to have produced the summary for a lot of the day.

But what's really important is that third bullet; capability to deliver high value resources, rapid response, real-time pricing control signals, communications, right, and leveraging open standards.

You know, we've been implementing OpenADR 1.0. SMUD's C load platform is not the same as the as the Cua.com's (phonetic). Well, guess who was there first.

So, I've become someone adept at learning how to modify a Cua.com specification client to work with Lockheed Martin systems.

Highly scalable and flexible, this is one of the real tenets that has to be in place, right.

Tracking of DR resources for reporting, one of the challenges right now is that NERC is more interested in what we're doing than ever. Right, we've got WECC reporting, we have SMUD internal reporting. How do we capture all that and report it?

Well, right now everybody has a different definition of these things and the programs that I created don't even fit into the standard models that the rest of the reporting structure has. So, that's a challenge. It's like if you want to do something innovative, where do you put it?

And then really important, cyber security is built and tested. I like the internet. Millions of people every day make a lot of money making -- trying to make that as secure as possible. You know, I think that's a good way to go.

And the next slide, please. So, today's demand response, I'm going to add to the alphabet soup here. SSN, MDMS, EMS, GIS, SAP, ACLM, DADMS, LMS. Anybody know what half of those mean?

I'll give you a real quick, Silver Springs Network, you know, that's handling our meter data.

MDMS, that's Itron, that's the meter data management system.

EMS, that's our SCADA system, that's what runs our plan.

GIS, that's how we figure out where all this stuff is and how we talk to it, right.

SAP, that's our whole business backbone.

That's just the top level of the integration that I'm going to take you through in a second.

Air conditioning load management, that's our legacy system.

Ultimately, we want to migrate it all into a single platform.

Distribution automation, distribution management system and the operation system those are all integration points that we want to have into our demand response.

The next bullet there, it's automated and machine to machine. I think this is absolutely critical.

You know, a little preview, I guess, of what we've discovered so far is that as I'm starting to implement this auto DR pilot program for 2013 the record holder for the time, and I have my watch pretty much synchronized up to our demand response management system, a 3:00 event, the lighting contactor opened at 3:00 and 16 seconds.

Okay, the longest round trip for getting the auto DR to response so far has been about a minute, 45 seconds, with a one minute polling, so depending on where you catch it in the polling cycle.

What this is telling me is that this is extremely fast and this part has been extremely reliable.

And I've suddenly got a whole new interest in package units, and I'll explain a little bit more.

So, we're communicating over the internet with OpenADR 1.0. As soon as we cut our teeth with what we have, I want to migrate to OpenADR 2.0 and really start exploring the capabilities in there.

The DMS is connected through the Silver Springs network. It also has a broadband interface directly with customer systems and that is on the residential side and the small commercial side.

And that, as I mentioned, ultimately we want to support all of our systems through our demand response management system and then, once again, integrating it with distribution, automation, DMS and LMS.

And I think I have this kind of future looking vision that, you know, maybe we could manage autonomously on a feeder if the whole system knew, you know, what load resources are available? What renewables are out there? How much load is there? How much is the price at that feeder right now? And let the system, you know, automate that and manage it with oversight from the operations.

It's going to take a long time to get there but I think there is tremendous value to be unlocked in that kind of scenario.

The next slide, please. So, combinations with DR; how many of these have we heard today? Trust in the availability and the reliability of the resource.

What I'm giving you, basically, here is this internal issue exists within SMUD as it does within the rest of the State and the rest of the country, actually.

These issues are common no matter who you're talking to and, you know, whether it's an operator or a system planner you're looking at what kind of resources are available.

Everybody's used to pushing a button, but not even a combined cycle -- I mean a simple-cycle gas turbine has 100 percent reliability, right.

If you figure out what that thing's producing so, okay, I sell you a generator that's got a 50-megawatt load reduction -- I mean a production potential, I look at it at the end of ten minutes and say what did you give me?

Right, I think demand response has those same kind of characteristics and we quantify what it is that we're getting and then that's where we categorize it.

Uncertainty in the sustainability of the resource, I'm going to address this a little bit more. Everybody says, oh, you know, I've hit that too much, customers aren't there, they bail from the program. We've all seen it.

I think there's a lot of room for working on that particular aspect.

Alignment in competition with traditional resources, both in constant capability, in SMUD everything I do has to compete with the supply side. And right now capacity options are very cheap and they've been that way.

So, you know, the challenge is how do we get the investment before we actually need this?

Somebody else earlier today had a slide up there that said you need 18 to 36 months, I think this was Comverge, to lead time for the full program capability. That's absolutely true.

You know, you can't turn the switch on this tomorrow. You need to really think ahead. What do you need, what characteristics do you need, and how long it's going to take to build it?

Then you've got to build the infrastructure, you've got to design and conduct the pilots, right.

And then the big part of what we're trying to look at for 2013 is what are those characteristics? You know, what's the ramp rate? What's the availability? What's the duration?

You know, all of those things that we can go back and look at and say, you know, what's our resource mix?

Here's the kinds of things that we buy, make, trade, sell or consume. Where do these products fit given the characteristics that we've identified?

This is absolutely critical to establishing the value that we're going to be able to derive from here.

And then demonstrating the viability of the programs and the value of the resources, the challenge that I have and that many people in this room have, you need to prove it to me, you need to show me that it's going to work, I need to know that it's going to be there when I need it.

Because if I need it and you said it's there, and I push the button and it's not, it's worse than if I never had it in the first place because I would have made other plans.

So that's the challenge and it exists throughout this whole environment, not just at SMUD.

The slide, please.

COMMISSIONER MC ALLISTER: Hey, Harland, can I, on that next-to-the-last point there, what's the process that SMUD's going through to establish those characteristics to really vet what the details of the products are that you're going to be looking for?

MR. COOMES: So, we've established a Demand Response Working Group back in 2011. We got an internal team of stakeholders together and we spent about six months figuring out what do those resource products look like.

And I shared this with Heather, we weren't all speaking the same language, even though we all work with the same thing because three different areas of this elephant are looked at from three different angles, right.

So, one of the first things was let's get a common language together about what this means. When we say RA, what are we talking about?

When we say non-spin or spin what does that really mean?

I think that's one of the first things is it's got to be in a common language that everybody agrees to.

So, the outcome of that was to basically put together a few tables that really related to what are all those resources that we buy, make, trade, sell or consume, right, and what do they look like? And then what are the demand response characteristics that look like those things?

And then what do we actually have is the part that I'm at now. So, the 2013 pilot is going to have a lot of M&V associated with it, with understanding those characteristics, the ramp rate, you know, the availability of the duration, you know, all of those things that are of interest to us, in addition to how much is it going to cost to do all this on both a start-up and a sustaining basis.

COMMISSIONER MC ALLISTER: Okay, thanks.

MR. COOMES: Sure. The next slide, please.

So, I call this the egg chart because it's about the closet thing I've got to a picture today, so bear with me.

But there's a lot of information packed into this, but if you'd just focus on the bold eggs here.

The DRMS provides us a tremendous amount of capability that we did not have automated before. So you've got communication, management, customer's programs, technology, the events, the settlement, all of those kinds of things originate from the DRMS.

Signal capability, price, reliability, proxy AGC, you know, we've got the ability to channel these kinds of things directly into devices and, henceforth into customers.

High-value DR, now you've heard me say that a couple of times, now. You know, one of the things that we can't import is regulation, right? So, how many megawatts of regulation is an interesting level for SMUD, and what does that look like?

You know, do we take banks of customers and rotate them through regulation duty, regulation service one or two hours a day, or something like that, and then how do we compensate that, right.

But it's economic, reliability, operations and environmental.

Myself, and I think a few others, I foresee a carbon-constrained dispatch future. I think there's going to be a day when we have to make a decision about whether or not we run a simple-cycle gas turbine versus dispatching a demand response event because of some kind of carbon consideration.

I don't know what that's going to look like, yet. I don't know how much it's going to cost, but I believe that may happen.

Resource planning, load reduction, forecasting and analysis, that's a big element of what comes out of here.

And then I mentioned the system integration, fast DR, regulation, firming reserves, that's ultra-fast. I think I've already talked to you about how fast the current DR is.

And, you know, we're looking at resource adequacy, reserves, reliability, economic dispatch, those kinds of things.

But that's the capability that the DRMS is providing us, now, and we're just now beginning to understand more about its capabilities.

The next slide, please. So, meeting needs and providing solutions. I think we've heard a lot about the left side of the column.

You know, spin, non-spin, regulation, these are kind of the stock in trade.

Location, sub-station feeder transformer options, we have load growth, we have electric vehicle penetration, we have renewable integration. These things are going to tax the very local devices, like transformers, that are serving small areas of the community.

And transmission distribution investment alternative, those of you that spend your time in here know that this is a major challenge because, you know, do you build a substation transformer that you can make money off of for 50 years, or do you gamble that you're demand response resource is going to be there and alleviate some of the need for that resource?

Well, if you under-build it, you've got trouble from the beginning. So, you know, reliable utility practices, I've got to make sure what I build is accurate.

BANC, the Balancing Authority of Northern California, SMUD is a member and an operator of BANC. It has resource needs. It's a possibility that that can be served through demand response.

And then the menu approach on the right-hand side. You know, we've talked a lot about, you know, categorizing different kinds of resource products. Here's a good laundry list of all the different things that are out there and they all have different characteristics.

You heard Mary Ann talk about storage, thermal, electrical and other. You know, I've become acutely interested in repurposing TOU -- not TOU -- thermal energy storage. You know, I've got 3 or 4 megawatts worth of chiller load, what can I do with that?

It's already designed to cycle. So, how do I take things that are already engineered to cycle and do something new with them?

Special contracts, I think we're always going to have those. We've got customers with particular characteristics that we want to take advantage of.

And then voluntary emergency curtailment this is, you know, the folks that have volunteered to go home, shut down their businesses when things are really tight. We don't call them unless it's critical, but they're there, and then the BANC resources.

The next slide, please. So, what are we trying to do for 2014 and beyond? We want to integrate all of this, right, in committed, ongoing, long-term activity. I think those things are really key. It's been an integral part of our integrated resource planning.

But the challenge is you've got to build me what's reasonable, cost-effective, and achievable. Right, that's kind of the mandate that was handed down.

And we need funding commitments to do that. We want to leverage all this Smart Grid stuff that we've built with a grant.

We want technology enhancement. As I mentioned, we're at the beginning of this. Silver Springs needs work, DRMS needs more work, metering platforms need more work.

Right, Silver Springs can't deliver a real-time meter read back, so how do we work with that? You know, what do we do to try to overcome that?

And exploring integration of DR into the distribution management systems, you know, I think that you’re looking at a very multi-year road map here with a lot of integration.

The next slide, please. So, develop auto DR to its full potential. I think 40 megawatts or more is a very realistic goal for the next few years.

Small commercial and residential DR, one of the things that we’re finding is that the technology -- you know, SCP 2.0 just got approved. OpenADR 2.0 devices aren’t really prevalent, yet, but they’re getting there.

On the residential side we’re not ready to do a wholesale technology deployment to replace our switches with the air conditioning load management.

We’re not seeing enough interoperability there. We’re seeing a lot of challenges in integrating with some of these existing platforms that our current providers out there have.

Customer response to program designs and technology options, we really need to take a look at that. You know, what are they interested in? Someone else had mentioned that earlier today.

And then, as I mentioned, migration from ACLM to a new model. We’re going to continue to operate our good old switches for some time to come, as the technology standardizes and matures.

So, you know, right, a number of years ago, in about 2000, we reconfigured our air conditioning load management program to be one minute, basically things happened quickly in one minute if you pushed the buttons, and it's also throttle-able.

So, it's still a good resource although it's not -- you know, it's dumb, right, it's got one way. We don't really know if all the switches work, we don't really know what happens, but we can see the effect.

And then the last big bullet here, develop DR portfolios reasonable and achievable. At our -- the peak of my involvement as a planner of these types of programs, we had 8.8 percent of our load under some kind of demand response back in 1995. And then, you know, things changed, de-regulation came about, different types of resources mix came available. And we used to use it regularly.

You know, customers liked it, they were part of the Peak Corps.

So, today, you know, we're down in the 3, 4 percent range. But if we get at this again and put a sustained commitment behind it we believe we can get back up to about 9 percent of our system load by 2021.

The next slide, please. So, implementation, right, the new DR is multi-dimensional. You know, I think we've talked a lot about that today, but it's very true.

You can take, with the technology we have and the additional capabilities we can do a lot of things, rather than just pigeon hole one type of resource in one place, we can look creatively at it and say, okay, can this serve more than one purpose, you know.

The business processes, technology, policy and program design, this has been a big challenge and an ongoing work in progress for us.

Because of the grant that we received, we had to do all of this in parallel. And, really, you can say, wow, how do you start without the policy. Well, you start because the DOE gave you a deadline that you can't move.

And there was actually some advantages to that because we've been literally building it and learning how to build it as we've gone. So, the business process has evolved, we've uncovered different aspects of our systems that we needed to improve or modify.

But it's, as I mentioned, an ongoing learning opportunity.

So, in order to meet those aggressive schedules we had to move in parallel, there was just no other way to do it.

And, you know, the last bullet there, we built it, now we have to learn how to use it.

This is not tongue in cheek, this is reality. It’s like I’ve got all this, I’ve got this auto DR program I’ve been working on, I’ve got this DRMS, I’ve got all this capability, I’ve got OpenADR 1.0, I’ve got OpenADR 2.0, and I’ve got customers that are interested, now what do I do with it.

And as I mentioned, we’ve just begun to explore the capability that we have. I think the exploration of what we can do with this is really at its -- we haven’t even crawled, yet. And so it’s a pretty exciting opportunity.

So, David wanted me to talk a little bit about another example. So, here’s the auto DR pilot program, the Power Direct. The program design goals were to provide a reliable, predictable, and sustainable load reduction, ease of compliance both with us and the customer, and then I wanted to encourage maximum performance.

So, what I did is kind of took the whole way that we always plan these programs and I turned it on its head and I said what do I really want? I really want reliable and sustainable load reduction and I'll pay people to over-perform.

That was really the genesis of the idea that morphed into this program.

And then I've got to provide customer choice. So, I'm going to give them four program options to meet both customer and SMUD business needs, and largely they're based on risk, if you read between the lines. Risk for SMUD and risk for the customer, it's a balancing act.

They're both available for economic and reliability dispatch. The DRMS gives us the ability to actually parse off part of these programs and reserve it for an economic commitment, and leave the rest for operations later in the day, or the next day.

Some of the significant program features, designed to accommodate shorter, more frequent dispatch. Hey, I personally think that the days of, you know, having one resource deliver a four- to six-hour load reduction day in and day out, I think that's a non -- I don't think that's going to happen.

You know, I think that we need to think about short duration, load firming, renewable tracking, following. Pick your description that you want to use. But I think the future is more frequent events of shorter duration.

And when I put this program together I got together with our Smart Sacramento partners and I said I'm going to design the programs, I want your input. You know, and I've been working with many of these folks for many years and said how can you -- how would you manage this? Oh, well, you know, don't lock us into a contract we can't perform. Don't give us targets and things like that we can't make.

Great. So, what if I help you with targets and give you flexibility? Yeah, yeah, we can do that.

So, the end result of that was that there is a cap on the total number of events over two hours, limiting that to 12, no more than three consecutive days in a 14-day period.

But under two hours, the number of dispatches is unlimited. This is the first time we've ever done anything like this.

So, automated notification, dispatch and settlement, this is really important. We don't have the manpower and I don't have the budget to manually settle this stuff. So, we have been working very systematically on setting up the settlement so it's all automated. That includes generation of target load profiles.

The other thing is I don't want to have anything to do with bidding. So, all of these customers are in the program with a target. Two of the program options, one is a firm load reduction. One is a minimum dependable load reduction. Notice the names.

They both have capacity payments. One has a pre-determined capacity level they have to get to. The other one has a band of 50 to 150 percent of a target by hour, by month.

And then one is a critical peak pricing program. The difference there between what we've traditionally done is it's dynamic. That critical peak pricing period is tied to actual event duration, not a pre-defined four hours every time we push the button.

And then the last option, you know, which is basically what I call the learning program, is a purely voluntary program where we just pay for what we get from a baseline.

There's no contract. It's got an energy payment that's a little bit lower than the other programs, but customers can get in there and they can learn how to use their systems. And my hope is that we'll help them migrate to a higher-value option.

The next slide, please. So, start the discussion. You know, we've gone through a lot of these kinds of questions today, right, what opportunities does it present?

I mean, how will everybody work together to explore it? You know, how do we build demand response that’s reasonable, achievable and cost effective? And, you know, what is needed to gain a long-term commitment to develop it?

I think probably nobody in here is aware of the fact you are sitting in an auto-DR enabled building right now, that is pulling the SMUD demand response management system. And as of last week, Department of General Services delivered a contract to SMUD to go into the auto DR program.

So, we’re talking about reality right here. So, you know, in theory if I walked back to my desk I could schedule an event. The operator in the central plant could enable the auto DR and temperatures would reset. There’s three states of auto DR that’s built into nine DGS buildings down here. And we’re really exciting to have them participate. That was an outgrowth of the Smart Sacramento grant.

I’d like to just close with one quote and, you know, pardon me for pulling in things that are seemingly unrelated, but I think there’s some interest here.

This came out of an article called “Boston’s

Unity of Effort", by Donald F. Kettle, out of *Governing Magazine* for June.

And he's talking about, basically, the question of who's in charge.

But the thing that I think that's really important and relevant to us is that it says -- there's a quote in here that says, "Effective response begins with a strong integrated, practiced and advanced response, coupled with a nimble problem-solving ability."

I think that serves as a bit of a marker for us. You know, they refer to it as local because, of course, it was emergency response, but there's a local element in here as well, but we also need the system wide element.

So, thank you very much.

(Applause)

COMMISSIONER MC ALLISTER: Thanks to all of you who presented this last session, it was very, very helpful.

I was writing down questions as you were talking and then you promptly answered the vast majority of them before I almost finished writing it down.

But, you know, I think SMUD obviously has -- it's a good test case for things like this because, you know, it's sort of simpler in a lot of ways and you're all integrated across the board. So, some of these, you know, sort of jurisdictional/institutional kind of barriers sort of just don't apply and then you can kind of go out and do what you want, which I really appreciate.

So thanks for putting yourselves out there on some of this stuff and, you know, rolling up your sleeves and learning the lessons sort of proactively.

I guess, I wanted to get a sense of the scale of your program and sort of how you do customer acquisition on this stuff?

And the reason I ask is sort of, you know, I have some now antiquated experience with demand response in Southern California and sort of, you know, the demand response audit, and you sort of pitch it to the customer, and you try to combine with energy efficiency, and sort of the customer decides down the road where they want to sign up, and they may or may not get called. And it sort of -- it just took a while and kind of, you know, that's been a number of years.

So, the programs now are sort of, I think, much more tuned to the need, for sure, of the customer and the system.

But I want to kind of get a sense of what that process looks like at SMUD and, in particular, what -- when you determine what sorts of loads could do what, both for your system and for the customer, sort of how that interface actually happens, and how you figure that out and then move forward.

MR. COOMES: Okay, let me see if I can capture it in fewer words. So, as far as the energy efficiency and demand response let me hit that first. A major milestone with the grant programs, we had an energy management control system program, and also an advanced lighting control program, which I worked with the program managers and we integrated demand response capability, auto DR capability as a requirement of getting into that program and getting that technology.

We've also put together a definition for what auto DR capable and what auto DR enabled means because that has a very specific meaning within SMUD.

Capable means that I can connect to it, I can communicate with it, it's got the capability to be programmed and so enabled means that all those things are in place, right.

If I can get the energy efficiency program to put in auto DR capable, auto DR enabled is a very short leap and it doesn't take much of a business case to make that happen.

If I try to go to a customer and do auto DR enabled as the only opportunity, there's just not enough money on the table to really make that attractive.

So, the auto DR capability is a big deal in getting that instituted as part of an energy efficiency program.

And we've just -- as I said, we've got a couple of good examples of that and I think it's going to be institutionalized, now, on a -- you know, I personally don't want to see another energy management system go into a SMUD -- as part of a SMUD program that isn't auto DR capable.

So, back to the process, we're pretty selective about who we recruited for this. You know, we were looking for customers that could move quickly, they already had some capability. We didn't have much time, the DOE grant deadline was April 22nd, then we grabbed them for a little bit longer and then May 31st is when the incentive -- you know, basically, my ability to recruit and pay incentives to customers ended. So, this happened very, very fast.

The process that we used is basically to go out and look at our customer base, what kind of loads we have. You heard Target earlier today. You know, they were one of the first ones to jump in with a signed contract with us and were wonderful to work with.

And then we do a preliminary site assessment and a detailed site assessment with the help of Global Energy Partners, who we've got under contract.

So, basically there's myself, a person that's in charge of recruiting the customers, and Global Energy Partners that are making this happen right now, and then a whole bunch of people behind the scenes, but we're the customer-facing end.

And then from that, you know, we have a pretty straight forward contract. I've managed to pare it way down, and it's got basically three attachments in it. One describes the program that they've signed up for, another one is the terms and conditions for their participation, and which -- and then we construct a target load profile and we determine what their incentives are going to be based on, which is the highest average hour for the year, for June through September.

And then we establish what that hourly load profile should look like. And I do that for both the -- creating a target for both the capacity payment programs, as well as the voluntary. And the idea being, you know, let's see if we can get something up there the customers can shoot for.

We had a lot of success with the demand bid program back in 2000-2001, but there's a lot more technical nuances that I need to work through. But I want to see what happens and so far the initial testing has been that it's proven to be fairly accurate so far. So, we'll see how this unfolds. This is a learning experience this summer.

And then at that point we do a functional test. At this point we're calculating what the load reduction's going to be and that's what we're paying the technical incentive on.

And then we'll see how they actually perform. And that's basically it, once they're connected, functionally tested, the contract's complete and they're pulling the demand response management system they are ready to be dispatched.

COMMISSIONER MC ALLISTER: Great, thanks very much for that.

And then, Commissioner Peterman, or Audrey, or Heather do you have any questions?

All right, we're pushing the time limit so, Suzanne, I think rather than take up a half an hour on lead Commissioner comments, let's go to public comments and see if we have any other input.

I know there's a lot of people who have been sitting patiently here, in the room.

MS. KOROSEC: I know I did have two people who specifically asked to speak, but anybody can come up. But our first was Catherine Hackney, from Southern California Edison.

COMMISSIONER MC ALLISTER: Right.

MS. HACKNEY: Thank you very much. We very much appreciate the opportunity to be here today. Thank you for gathering this incredible collection of experts and enthusiasts.

You know, I listened with great interest to customers, aggregators, policy makers, regulators, the technical folks who are well behind my current level of understanding and I now fully embrace and am looking forward to this great adventure.

I would, in the interest of time, just like to take a moment to share with you an effort that is underway at Edison.

We have been looking at how to meet reliability needs in the L.A. Basin in the year 2022. The effort was driven largely in part by the OTC retirements, more recently by SONGS retirement.

The most important thing, I think, for this audience today is that the strategy under development is looking very closely at preferred resources, demand response, obviously energy efficiency, distributed generation and storage.

A key recommendation coming out of this proposal is to develop and implement a pilot program targeted in South Orange County.

Our analysis has identified a couple of key geographic regions that would be particularly effective if we were to make targeted investments.

We are going to be seeking authorization from the Commission to take advantage of that 400 megawatts, up to 400 megawatts that were authorized as optional within our LTPP track one. We'll seek authority to procure up to those 400 megawatts of competitively priced, preferred resources to meet reliability needs.

A few weeks ago, Commissioner McAllister, we had the opportunity to meet with you and kind of outline this thinking, and you shared with us some very key and important thoughts at the time.

You suggested that if you're going to undertake this kind of effort that you need to make sure you have the right metrics, measurements, reporting protocol so that what you get is something that will be useful, and inform procurement, planning, customers, aggregators, et cetera.

You also indicated that a single pilot isn't particularly useful unless it's designed to be a living pilot.

So, we have taken those suggestions to heart and that is what we will be beginning to develop in collaboration with you, your staff, the PUC, the CAISO, and stakeholders, many of whom I'm sure are in this room today.

So, again thank you very much. We look forward to working with you and we really do think, just as SMUD was suggesting -- I mean they're doing what we can only imagine, right.

But what we think a pilot would do in the South Orange County area, it would give real-time, real-world information to us to inform the decisions that we're struggling with today. So, thank you so much for your time. Appreciate a wonderful day.

COMMISSIONER MC ALLISTER: Well, thanks for being here. I'm glad I still agree with what I said a few weeks ago.

MS. HACKNEY: Oh, one last thing. As Commissioner Florio was exiting I spent about three seconds describing what we wanted to propose. His initial response was "You betcha!" Now, that's not official, but it's certainly indicative that the direction that we're headed is a positive one so, thank you.

MS. KOROSEC: Next we have Pierre Bull from Natural Resources Defense Council.

MR. BULL: Thank you for having us here. As I think one of the lone environmental stakeholders, we are very pleased to see this forum take place.

As you know, the NRDC has been involved in energy efficiency for many decades now, and in advancing that policy in the State of California. And we're also very interested in renewables integration and scaling up renewables to meet the needs that efficiency can't meet.

Again, there's great potential for DSM resources to lower costs, improve reliability and reduce the environmental impact of the electric system.

DSM resources, efficiency in particular, have a proven track record of providing enormous low-cost resource over the last few decades.

Again, in meeting the flexible two-way needs of a modern grid, demand response and efficiency can play complimentary roles.

Demand response can facilitate the integration of renewable resources by playing a balancing role, both for in and out-of-state renewables, both large and small, when flexible attributes are both properly defined and accounted for.

And efficiency, then, plays a distinct, but complementary role in maintaining grid reliability. Efficiency can reduce the absolute amount of flexible resources needed to begin with by reducing load altogether and reshaping the load curve.

Again, the SONGS outage, as we heard with Edison just a second ago, is an immediate opportunity to show its leadership in maximizing the use of preferred resources and we should get started on that right away.

Again, we applaud the spirit of this forum in providing a way to work together to establish a statewide forum of all technical experts to vet the energy savings estimates and demand responsive potential in a transparent and collaborative process.

And the final couple of points to make is that Commissioner Peterman had asked the question earlier, we definitely need to ensure that we don't go backwards in demand response, and make sure that we are only getting truly clean and sort of non-utility backup generators that could be diesel, or other fossil fuel-fired, dirty generation sources.

And, finally, we need to make sure that we are defining procurement eligibility rules to make sure that efficiency and demand response don't necessarily have to dress up like a generator. We've heard that many times that it is a different resource and should be treated as such.

Thank you for time to comment.

COMMISSIONER MC ALLISTER: Thanks for being here and sticking it out until the bitter end here.

But I want to encourage everyone, actually, to submit written comments. You know, if you've got that burning point that you want to make and weren't able to make here today, or really just more detail on, you know, your particular viewpoint or the sets of issues that you want to bring to us.

Written comments are due on July the 1st and we really appreciate folks bringing their best thinking to this task. As you've heard today, there's a lot of moving parts and there's a lot going on with this topic of demand response.

And so we, all the agencies are really committed to figuring it out and moving forward in a productive way and I think you all can really contribute to that. So, thank you for being here and -- no, no, no, I'm not closing out, don't worry.

(Laughter)

COMMISSIONER MC ALLISTER: I just wanted to get that on the record before people start heading out here.

MR. BULL: Thank you.

COMMISSIONER MC ALLISTER: But thanks very much.

MS. KOROSEC: All right, I'll open it up broader, please come up, sir.

MR. ABREU: Thank you. I didn't want to hold up your show there. My name is Ken Abreu. I work for the Pacific Gas & Electric Company, in the Demand Response Department and I handle the policy and planning side of that.

Thank you for having the meeting today and giving us a little time to speak.

Just a few highlights I think that's good to know just from a factual basis about PG&E and DR. We have 700 megawatts of DR today, 500 megawatts of that is dispatchable in 30 minutes or less, and 200 megawatts of that, roughly, is already automated demand response.

We were the first and may have been the only entity to ever bid into the CAISO market, under the PDR program. We did that in 2011 and 2012.

And we have a pilot, which has just been approved and which we're moving forward with later this year for demonstrating DR as a flexible resource.

With that I just wanted to make a couple of comments on your panels and some of the key points that came out of that.

On the customer perspective, I think the key point to draw from that is it's important to retain both retail, as well as wholesale programs. It was good to hear from the road map, and from Audrey Lee's statements, that you're going to look above the supply and demand side for DR.

I think that where you put things is going to be very important and I think a key criteria for that is everything pretty much now is on the demand side. And the question needs to be asked, when we move it over to the supply side, do the costs incurred in doing that, which are significant, justify -- are they justified by the benefits in moving it over.

And there's a couple of ways of dealing with that. One is you can simplify some of the costs of moving it over through some of the things that the ISO's working on or needs to work on in terms of simplifying their rules.

I think the other point was one made by the aggregators. You need to start out simple and get more complex over time. Don't try and change everything that's working today, just add to what's working today with some new things moving forward.

Your second panel was on the aggregator perspective and a couple of points there, and I think some of you have seen this before, to give those folks the stability and the knowledge that things are going to be around for the long term and for us, as an LSE, to know that we have them in the long term. We'd like to continue doing long-term RFOs, RFPs with the aggregators.

The next ones are going to end at the end of next year, which is not very far off, and so we'd like to get that underway fairly soon.

It doesn't necessarily need to be for these new sophisticated products because we're going to still need those base-type projects -- products that we have today going forward.

And we can do future RFPs as the definition of more sophisticated products comes into play. But giving our customers, giving our aggregators and giving our own people some certainty about the future is very valuable for making sure they can do new things going forward.

Another thing that the PUC can do is work on fixing the deficiencies in the cost-effectiveness methodology. Right now it's acknowledged by the PUC that there are some significant deficiencies in that.

And if we're going to do a new RFO, or anything, we need to fix those deficiencies ahead of time or you're not going to get as much DR as you're really going to get. And that's already impacted the size of our DR structure.

In terms of the market structure, I think that the key point there is as you're looking to solve the duck problem, don't just look for high-speed, rapidly-moving type resources.

Things like energy efficiency, our time-of-use rate structure, our permanent load-shifting programs can all change that load shape and reduce the amount of the problem and then your flexible resources, which are going to be your most expensive resources can come in and solve those problems.

But the targeting of things like our permanent load-shifting programs, or our time-of-use rates, or energy efficiency programs are things we're already going to spend money on, so let's just put those to their proper use and we can reduce the problem without having to spend maybe quite as much money, and try to do quite as many sophisticated things.

Okay, that's all I really had. Thank you very much.

COMMISSIONER MC ALLISTER: Okay, thanks very much fo9r being here.

COMMISSIONER PETERMAN: Oh, I just wanted to add on your last point about the duck chart that I appreciate those co9mments, because I think the idea is that you use the flexible resources for the part that you can control otherwise.

In addition to the list you listed, also just improved forecasting around our renewables helps us manage that, as well as a diversified portfolio with renewables that are less intermittent.

And those are all things under consideration with the RPS, particularly there's focus on looking at integration costs and adders in that regard because that's really what we're talking about in terms of the size of that belly. So, I'm in full agreement with you there.

MR. BRUNELLO: Hi, my name's Tony Brunello. I just had a short, 15-minute presentation I wanted to give.

(Laughter)

MR. BRUNELLO: No, just kidding. I just wanted to say thanks, it's very encouraging to have you guys working so closely together, first of all, so that's excellent and really appreciate the opportunity.

The second is just to follow-on Commissioner Hochschild's comments. We really believe that there's tons of opportunities with demand response and energy efficiency, similar as we've seen in solar.

So, encourage you guys to be bold, as you're doing, and very much appreciate the work you're doing.

Finally, as I hope on some of the future proceedings maybe we can include some additional companies that might be outside of the traditional groups that we've had here.

Obviously, ones like Nest, or others that are very innovative programs that I think are worth people hearing since they're really less from the experiences from the past and looking at, really, what might change in the next two or three years.

There's also a lot of changes in consumer electronics. Groups like Arm Holdings, and others that are really looking at the internet of things. More things are going to be connected that will definitely play a factor in some of the proceedings in the future.

So, we'll submit comments, but I just wanted to say thanks again and appreciate today's workshop, very helpful.

COMMISSIONER MC ALLISTER: Thanks very much, Tony. And then, you know, it could have come up multiple times I think today, but you mentioned Nest. And, you know, that's an entity that's essentially selling a consumer product that helps people save energy and lower their utility bills, and it's an interconnected device. It's an internet-connected device, right.

So, it uses, you know, intelligent design to learn how people actually utilize their HVAC systems and then could, presumably, and is I believe in the process of essentially packaging DR products to then sell to utilities, or whoever else, whatever other market is out there.

So, you've got kind of a back-channel way to get to influencing loads that then has some monetary value. So, it's a kind of an interesting business model in that way.

The HVAC manufacturers, you know, clearly -- you know, you talked about appliance and consumer electronics, but other appliances -- you know, a lot of the load we're talking about in residential and small commercial, for example, is package units, or splits, or small HVAC. And, you know, I think those devices for business reasons -- actually, there's a lot of reasons why the manufacturers would want to make them interconnected and be able to communicate with them.

And so those technologies, maybe even the way they get developed is through appliance standards at DOE, or some -- you know, some building standards here in California, in some way.

But again, that functionality then could really be relevant for putting together demand response products and getting them into the market, maybe even bidding into some market that the PUC and the ISO were to have.

So, I agree with you that the potential for really innovative approaches to this is all over. And, you know, we definitely, I think, need to be open to all that kind of stuff.

So, I'm looking forward to your comments on those issues.

MS. KOROSEC: Do we have anymore comments from folks in the room?

All right, we did have one question online for Heather, about your world-famous duck.

"The recent decision to shut down SONGS effectively removes 3,000 megawatts of generation. Does the duck projection include that or does that generation loss make the curve even deeper?"

MS. SANDERS: The SONGS outage is 2,200 megawatts. The duck reflects net load, so there isn't any generation included in that, that isn't variable.

So, the duck is calculated based on net load, so you take the load, you subtract out the wind and you subtract out the solar. So, load minus wind, minus solar, because what you're doing is you're reflecting what the operator needs to follow.

So, we need to follow variability. We need to have resources that can ramp up and ramp down with variability.

SONGS is a baseload resources. So, one of the implications of removing a very large baseload resource is that other resources need to fill in.

We have looked at what has happened in the last year with resource utilization and what we're noticing, especially in the south, is more predominant use of gas plants as baseload resources.

So, that's compromising, now, the ability to have more flexible resources available.

So, I hope that answers the question related to the duck chart. The duck chart illustrates variability and the needs of the system to follow that variability.

MS. KOROSEC: Great, thank you.

And do we have any other WebEx folks?

Okay, we do have two phone callers who have hung in here until the bitter end, so I'd like to open the lines to give them an opportunity to speak.

Can you go ahead and open the phone lines here? Just a moment.

All right, the phone lines are open if anyone would like to make a comment. Going once, going twice.

All right, thank you very much, I think we've given our public comment.

COMMISSIONER MC ALLISTER: Okay. Well, I will just wrap up and thank everybody for coming. I'm amazed how many of you have stuck it out until 5:20. You are good people and definitely, definitely energy nerds. And I say that -- I say that -- you should be proud. You should be proud of that, you're among friends.

And I'm really happy with the day the way went. I want to thank David, and Suzanne, and Lynette for keeping us all honest and more or less on track.

And please, again, submit comments. You know, a lot of this stuff was said. Some of it was not gone into -- you know, we didn't get to delve into a lot of detail.

But there's clearly a lot of interest across the board in the agencies on this stuff, from policy, markets, technology across the board on demand response. It's definitely on everybody's radar screen front and center as a resource that we need to develop and nurture, and figure out how to get right.

So, you know, I think the time -- a lot of ears are perked up on this issue and if you submit good comments, and sort of get them on the record in the various forums that we have going, certainly in the

IEPR, on the workshop -- I'm sorry, the road map discussion at the ISO, and currently end up coming -- at the PUC there will be a number of opportunities, as well, as we've heard.

You will receive, you will have an audience and you will definitely be heard and read. And I think it's going to really help us all align, develop the pathways forward and make them happen on a time frame, hopefully, that's sort of relevant for really getting past these issues in the near term that are coming up with renewables integration, SONGS and the other related issues that are out there.

So, I want to thank everybody for being here. Any need to make comments, I really welcome that.

COMMISSIONER PETERMAN: There's never a need, but I will anyway.

(Laughter)

COMMISSIONER PETERMAN: I'll just briefly say, again this is a very important issue to the Public Utilities Commission. The fact that you had as many PUC Commissioners and officers represented as Energy Commission officers should show you that importance. And I encourage you all to participate in the OAR development, and work with Audrey, and President Peevey as that office roles out our plan going forward which, of course, we'd like to have coordinated with the Energy Commission, and the ISO and all of you.

So thank you and thank you for holding this forum.

COMMISSIONER MC ALLISTER: Well, thank you all for coming again.

Heather, what am I -- no, right, we're all done. I think we're all going to head out to one of our fine eating establishments here in Sacramento so, please, feel free to -- please do pay attention to the comments that come in and submit your own. Thanks very much.

(Thereupon, the Workshop was adjourned at 5:20 p.m.)

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